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LIMITED ENERGY STUDIES

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KINGPORT, TENNESSEE

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LIST OF ABBREVIATIONS

Btu	-	British thermal unit
CHP	-	central heating plant
CO_2	-	carbon dioxide
DA	-	deaerator
ECIP	-	Energy Conservation Investment Program
ECO	-	Energy Conservation Opportunity
F	-	Fahrenheit
ft	-	foot, feet
FW	-	feedwater
gpm	-	gallons per minute
HAAP	-	Holston Army Ammunition Plant
hp	-	horsepower
hr	-	hour(s)
in.	-	inch(es)
I^2R	-	power loss
kBtu	-	British thermal units (thousand)
kV	-	kilovolts, one thousand volts
kVA	-	kilovolt-ampere, one thousand volt-ampere
kVAR	-	kilovolt ampere-reactive, one thousand volt-ampere reactive
kW	-	kilowatt, one thousand watts
kWh	-	kilowatt-hour, one thousand watthours
lbm	-	pounds mass
LCC	-	Life Cycle Cost
LCCID	-	Life Cycle Cost in Design
MBH	-	Btu per hour (million)
MBtu	-	British thermal units (million)
MCM	-	cicular mills (thousand)
O_2	-	oxygen
ppm	-	parts per million
PRV	-	pressure reducing valve
psia	-	pounds per square inch, absolute
psig	-	pounds per square inch, gauge

QRIP	-	Quick Recovery Investment Program
rpm	-	revolutions per minute
SIOH	-	supervision, inspection, and overhead
SIR	-	Savings-to-Investment Ratio: total life cycle benefits divided by the investment cost.
SOW	-	Scope of Work
V	-	volts

EXECUTIVE SUMMARY

INTRODUCTION

This study was conducted and this report prepared under Contract No. DACA 01-91-D-0032, Delivery Orders 2 and 3, issued by the U.S. Army Engineer District, Mobile on 9 September 1991. The purpose of this study was to determine the economic feasibility of the following specific energy conservation opportunities (ECOs) associated with the central heating plants at the Holston Army Ammunition Plant (HAAP):

- Area-B Cogeneration
- Area-B Vacuum Pump
- Area-B Intermediate Pressure Steam Header
- Area-B Combustion Air Preheaters
- Area-B Blowdown Heat Exchanger
- Area-B Condensate Collection
- Area-A Vacuum Pump
- Area-A Electric DA Pump
- Area-A Air Preheater
- Area-A and B Inlet Air Dampers

METHOD OF ANALYSIS

The method of analysis was as follows:

- A field survey was conducted to collect data for the analysis.

- Historical energy use data was collected and used to establish present energy usage and costs.

- An energy and mass balance was performed for each central heating plant using a computer boiler model developed for the project.

- Energy savings for each ECO was calculated using the computer boiler model or separate analysis as appropriate.

- Construction cost estimates were prepared for each ECO.

- A life cycle cost analysis was performed for each ECO using the latest version of the computer program, Life Cycle Cost In Design, (LCCID).

- This report was prepared, combining the two delivery orders into a single report.

PLANT DATA

Holston Army Ammunition Plant, located in Kingsport, Tennessee, is divided into two areas, each served by a central heating plant (CHP):

- Area-A is used for the concentration of weak acetic acid into glacial acetic acid and for the production of acetic anhydride. The CHP provides 400 psig steam for the processes.
- Area-B is used to make explosives on 10 separate production lines. The CHP provides 300 psig steam for the processes and for a significant space heating load.

ENERGY CONSUMPTION

Energy usage and cost is summarized in table ES-1 below.

TABLE ES-1
ENERGY USAGE AND COST

Energy Source	Annual Usage	Equivalent Energy Usage (MBtu)	Unit Energy Cost ($/MBtu)	Annual Energy Cost ($)
ELECTRICITY				
Area-A	11,008,500 kWh	37,572	4.67	175,461
	1,478 kW		9.50**	168,492
Area-B	58,753,500 kWh	200,526	4.67	936,456
	8,268 kW		9.50**	942,552
Subtotal	69,762,000 kWh	238,098		2,222,961
COAL				
Area-A	42,853 tons	1,208,454	1.25	1,510,568
Area-B	74,086 tons	2,089,225	1.25	2,611,531*
Subtotal	116,939 tons	3,297,680		4,122,100*
TOTAL		3,535,778		6,345,061*

* Includes cost for anthracite coal which previously was supplied to HAAP free of charge.
** Monthly demand charges ($/kW).

ENERGY CONSERVATION ANALYSIS

Area-B Cogeneration

This ECO evaluates installing a topping turbine and electric generator for Area-B. Steam is currently distributed from the CHP to Area-B at 300 psig. A new steam turbine-generator would accept steam at 300 psig, exhaust it to the steam distribution system at 110 psig, and generate about 800 kW.

Analysis of the cogeneration system proceeded as follows:

(1) Determine the amount of steam available for cogeneration. Building 334 requires process steam at 300 psig. In addition, 300 psig steam is required by the existing cogeneration system in Building B-6. Steam use by these two buildings is not available for cogeneration.

(2) Determine the minimum cogeneration back pressure required to meet peak steam demands under existing operating conditions. The cogeneration system defined by the SOW was based on the concept that the steam piping system, having been sized for full mobilization, could be operated at a lower pressure during peacetime. However, the administration and shop area steam piping are sized for existing demand and require high main pressures to meet peak space heating loads. This problem may be overcome by modifying the steam distribution system with the addition of a new six-inch steam line from the production area to the administration area.

(3) Optimize the cogeneration system for the best life cycle savings. This step required selecting the optimal steam turbine-generator equipment and size. The optimal system was one which supplied the base steam load.

Life cycle cost analysis was performed the following results:

Investment Cost	$829,000
First year energy cost savings	$95,957
SIR	2.4

There is an existing 400 kW steam turbine-generator in Building B-6. This existing sysm is only two years old, but inoperable due to a control problem. The existing steam turbine-generator should be repaired. The energy cost savings of the repaired generator would pay for the repairs within one month.

Area-B Vacuum Pump

This ECO consists of replacing the steam jet vacuum system on the Area-B ash handling system with a vacuum pump system.

Analysis indicated that a vacuum blower system is more cost effective than a liquid ring vacuum pump system. Under this ECO, the existing steam jet vacuum system would be replaced with a 50 hp vacuum blower system. Once the existing system is removed, the vacuum blower system may be installed in the same area as the steam jet vacuum system and air washer were located. The vacuum blower system would increase maintenance costs, but this would be more than offset by the annual energy savings.

Investment Cost	$34,900
First year energy cost savings	$10,119
SIR	4.1

The Area-B vacuum blower system is recommended for implementation.

Area-B Intermediate Pressure Steam Header

This ECO evaluates increasing the back pressure of the existing steam turbines used to drive the draft fans in the CHP and using the exhaust steam to heat feedwater. The back pressure of the draft fan turbines is currently 5 psig. It is proposed to raise the back pressure and use the higher temperature exhaust steam to increase the feedwater temperature to the economizer.

Under this ECO, a feedwater preheater would be installed between the DA heater and the boilers upstream of the economizers. The back pressure on each draft fan turbine would be increased and the steam exhaust routed to the new feedwater heater via an intermediate pressure steam header.

Investment Cost	$352,000
First year energy cost savings	$90,605
SIR	4.1

The Area-B intermediate pressure steam header is recommended for implementation.

Area-B Combustion Air Preheaters

This ECO evaluates installing a combustion air preheater on the Area-B boilers.

Under existing conditions combustion air is supplied to the boilers at an average of 56°F. The exhaust air leaving the economizer is 387°F. The minimum temperature to prevent corrosion in the flue is 280°F. This allows for a possible temperature difference of 107°F which could be used to increase the temperature of the combustion air.

Due to space limitations, the ECO modification is to install a run around heat recovery loop with a heat recovery coil located on the exit of the precipitator and a preheat coil located downstream of the forced draft fan.

In order to prevent corrosion in the flue, this system would be limited to 30% effectiveness. This would provide a combustion air temperature of 154°F. Boiler efficiency would be increased from 72% to 76%.

Investment Cost	$218,500
First year energy cost savings	$154,000
SIR	11.3

The Area-B combustion air preheater is recommended for implementation.

Area-B Blowdown Heat Exchanger

This ECO evaluates installing a heat exchanger to recover heat from the continuous blowdown of Area-B boilers.

Continuous blowdown from the boilers is currently piped to a flash tank which recovers flash steam for the deaerating (DA) heater. Blowdown liquid is piped to a floor drain. The blowdown rate was measured at 2.5% of the boiler steam production.

This ECO would be to install a heat exchanger to recover heat from the blowdown liquid exiting the flash tank. The heat exchanger would be installed in the make-up water line between the DA pump and the DA heater. Blowdown liquid from the flash tank would be piped to the shell side of the heat exchanger. The blowdown heat exchanger would add about 3°F to the make-up water temperature.

Investment Cost	$26,000
First year energy cost savings	$3,200
SIR	1.8

The Area-B blowdown heat exchanger is recommended for implementation.

Area-B Condensate Collection

This ECO evaluates installing a condensate collection system for condensate generated within the Area-B CHP.

Due to possible explosive contamination, no condensate is returned from Area-B to the CHP. However, condensate generated within the CHP could be returned. CHP condensate is routed to the waste treatment system via floor drains.

Under this ECO, condensate would be collected and pumped to the make-up water tank. Condensate receivers would be placed at each steam trap likely to produce significant condensate. Pumps within the condensate receivers would pump the condensate to the make-up water tank via a new piping system.

At average operating conditions, the amount of condensate generated within the CHP is 175 lbm/hr. The condensate would provide 0.2°F of make-up water heating.

A condensate collection system is not economically feasible. Condensate generation is small and simple economic payback is in excess of 25 years. The Area-B condensate collection system is not recommended.

Area-A Vacuum Pump

This ECO consists of replacing the steam jet vacuum system on the Area-A ash handling system with a vacuum pump system.

A vacuum blower system was found to be more cost-effective than a liquid ring vacuum pump system. Under this ECO the existing steam jet vacuum system would be replaced with a 50 hp vacuum blower system. Once the existing system is removed, the vacuum blower system may be installed in the same area as where the steam jet vacuum system and air washer were located. The vacuum blower system would increase maintenance costs, but this would be more than offset by the annual energy savings.

Investment Cost	$34,900
First year energy cost savings	$6,900
SIR	2.9

The Area-A vacuum blower system is recommended for implementation.

Area-A Electric DA Pump

This ECO evaluates installing a small auxiliary electric DA pump to bypass the existing large electric DA pump during normal operation.

The DA system uses a 100 hp electric pump to convey water from the makeup water tank to the DA heater. This 100 hp pump is sized for mobilization capacity. At average operating conditions the pump is operating at about 20% of rated capacity. The pump curve indicates that the pump is operating at a 40% efficiency as opposed to an 85% design efficiency.

Under this ECO, the 100 hp pump would remain, but be taken off line and a new 15 hp pump sized for present peak operating conditions would be installed and operated, thereby producing an energy savings due to both increased efficiency and smaller pump size.

Investment Cost	$21,400
First year energy cost savings	$4,329
SIR	4.2

The Area-A electric DA pump is recommended for implementation.

Area-A Air Preheater

This ECO evaluates the use of excess 5 psig steam to preheat the combustion air for the Area-A boilers.

Currently, excess 5 psig steam is vented to the atmosphere. The ECO modification is to place a steam preheater coil in the combustion air duct, downstream of the forced draft fan on each of the four boilers.

At average operating conditions, the steam preheat coil would raise the combustion air temperature from 56°F to 136°F and produce an approximate 3% increase in the central plant efficiency.

Investment Cost	$78,700
First year energy cost savings	$142,350
SIR	28.9

The Area-A air preheater is recommended for implementation.

Inlet Air Dampers

This ECO evaluates installing manually controlled inlet air dampers in the roof openings over the boilers. These dampers would be used to restrict the openings in the winter so that the warmer air from the upper level of the boiler plant would be pulled down by the forced draft fans. Higher temperature combustion air would result in higher boiler efficiency. This ECO applies to both Area-A and Area-B CHPs.

Operable dampers would be placed on each of the roof openings. During winter operation, only dampers above operating boilers would be opened; dampers over cold boilers would be closed. Air entering the CHP would then flow down over the hot boilers using boiler surface heat loss to preheat combustion air.

The average combustion air temperature is presently 56°F. It is estimated that average combustion air temperatures could be raised to 76°F. Raising the average combustion air temperature results in an average boiler efficiency increase from 71.5% to 73.3% in the Area-B CHP and a similar increase at Area-A.

Investment Cost	$96,700
First year energy cost savings	$53,655
SIR	8.9

Inlet air dampers are recommended for implementation.

RECOMMENDATIONS

Table ES-2 below summarizes the life cycle cost analyses for the recommended ECOs listed in order of economic benefit.

TABLE ES-2
RECOMMENDED ECOs

Energy Conservation Opportunity	Annual Electric Savings (MBtu)	Annual Coal Savings (MBtu)	Annual Energy Cost Savings ($)	Annual Electric Demand Savings ($)	Annual Maint. Cost Savings ($)	Invest-ment Cost ($)	SIR	Simple Payback (yrs)
Area-A Air Preheaters	0	113,900	142,350	0	(1,000)	78,700	28.9	0.6
Area-B Air Preheater	(10)	123,240	154,000	0	(1,000)	218,500	11.3	1.4
Inlet Air Dampers	0	42,924	53,655	0	(400)	96,700	8.9	1.8
Area-A Electric DA Pump	927	0	4,329	3,534	(400)	21,400	4.2	2.9
Area-B Steam Header	0	72,484	90,605	0	(400)	352,000	4.1	3.9
Area-B Vacuum Pump	(194)	8,820	10,119	0	(1,300)	34,900	4.1	4.0
Area-B Cogeneration	24,304	(14,045)	95,957	92,682	(6,400)	829,000	2.4	4.6
Area-A Vacuum Pump	(97)	5,883	6,901	0	(650)	34,900	2.9	5.6
Area-B Blowdown Heat Exchanger	0	2,556	3,195	0	(400)	26,100	1.8	9.3
TOTAL SAVINGS	33,902	355,762	602,997	130,416	(58,326)	1,698,200		
PERCENT SAVINGS	14.2	10.8	11.5	11.7				
NEW ENERGY USAGE	204,186	2,941,918	4,631,020	980,628				
PRESENT ENERGY USAGE	238,098	3,297,680	5,234,017	1,111,044				

TOTAL ENERGY SAVINGS

The summary of energy use and cost before and after implementation of all ECOs recommended in this report is shown in Table ES-3 below.

TABLE ES-3
TOTAL ENERGY SAVINGS

	Annual Electric Energy (MBtu)	Annual Electric Demand ($)	Annual Coal Energy (MBtu)	Total Annual Energy* ($)
BEFORE	238,098	1,111,044	3,297,680	6,345,061
AFTER	213,165	1,014,828	2,941,918	5,687,734
SAVINGS	24,933	96,126	355,762	653,327

*Includes energy and electric demand charges.

SECTION 1.0

INTRODUCTION

1.1 AUTHORITY FOR STUDY

This study was conducted and this report prepared under Contract No. DACA 01-91-D-0032, Delivery Orders 2 and 3, issued by the U.S. Army Engineer District, Mobile on 9 September 1991. Delivery Order 2 is for evaluation of identified boiler ECOs, and Delivery Order 3 is for evaluation of a cogeneration ECO.

1.2 PURPOSE OF STUDY

The purpose of this study is to determine the economic feasibility of specific energy conservation opportunities (ECOs) at the central heating plants in Area-A and Area-B of the Holston Army Ammunition Plant (HAAP):

- Area-B Cogeneration
- Area-B Vacuum Pumps
- Area-B Intermediate Pressure Steam Header
- Area-B Combustion Air Preheaters
- Area-B Blowdown Heat Exchanger
- Area-B Condensate Collection
- Area-A Vacuum Pump
- Area-A Electric DA Pump
- Area-A Air Preheater
- Area-A and B Inlet Air Dampers

1.3 SCOPE OF WORK

The Scope of Work requires evaluating the technical and economic feasibility of the following specific ECOs:

- Install a nominal 150,000 lbm/hr topping steam turbine-generator for the Area-B central heating plant (CHP). The existing steam distribution system supplies 300 psig steam through approximately 36,000 feet of pipe to production buildings throughout the site. A back-pressure turbine would throttle the pressure down from 300 to 150 psig while generating significant amounts of electricity.

- Replace the steam jets on the bag houses of the ash handling systems at the Areas A and B CHPs with a vacuum pump system.

- Increase the back pressure on auxiliary equipment turbine drives and use exhaust steam for pre-heating boiler feedwater upstream of the economizer at the Area-B CHP.

- Install air pre-heaters to recover heat from the flue gas and use for preheating combustion air in the Area-B CHP.

- Install a blowdown heat exchanger to recover blowdown thermal energy in the Area-B CHP.

- Install a condensate return system for condensate generated within the Area-B CHP.

- Install small electric pumps in the Area-A CHP to be used during times of low demand instead of operating the large electric pumps.

- Install steam combustion air preheaters in the Area-A CHP.

- Install operable dampers to recover heat from ceiling of the CHPs for Areas-A and B.

The following work was required under the Scope of Work:

- Review the the parts of the previous energy studies which apply to the specific ECOs.

- Perform a site survey to obtain necessary data to evaluate the applicable ECOs.

- Evaluate the selected ECOs to determine their feasibility. Savings to Investment Ratios (SIRs) shall be determined using current ECIP guidance.

- Provide all data, assumptions, and calculations showing how each ECO was evaluated. Prepare a LCC summary sheet for each ECO and include as part of the supporting data.

- Prepare a comprehensive report fully documenting the work accomplished. Submit an interim report for review. Complete the final report after review comments have been resolved.

- Conduct a formal presentation of the interim submittal to installation, command, and other government personnel.

The Scope of Work, dated 9 September 1991, is included in Appendix A along with applicable confirmation notices.

1.4 APPROACH

1.4.1 <u>Previous Studies</u>

HAAP has a number of study reports dating back to 1942. EMC was provided copies of these reports and also a copy of the Facilities Appraisal Manual. These reports provided steam load data for process heating requirements, space heating requirements, and steam pipe heat loss. These data were used in this study to size the Area-B cogeneration system.

1.4.2 Field Survey

The field survey was conducted during October 1991.

HAAP personnel were helpful in providing information and data. Plans and data on the plant were well organized and maintained in files and on microfilm in the engineering section at HAAP. Plans were obtained for the steam distribution system and for applicable parts of the CHPs.

Data was not available for process energy loads. This data was necessary to determine the adequacy of the steam distribution system to operate at lower steam pressure. Data on energy usage for processes and the amount of material processed was collected from previous studies and used to estimate process energy loads.

The Area-A CHP was surveyed to obtain data for analysis of possible ECOs. The Area-A CHP is well instrumented and operational readings were obtained from the existing instrumentation.

The Area-B CHP was surveyed to obtain data for analysis of possible ECOs. Measurements were made of temperatures at various points in the system and a flue gas analysis conducted. Boiler blowdown rate was also measured. Most of the ECOs are associated with the Area-B CHP.

Operating production buildings in Area-B were surveyed to determine required steam pressures and to obtain data on existing pressure reducing valves (PRVs). Production personnel provided an explanation of the processes. The cogeneration ECO is dependant on the ability of the production area to operate on lower pressure steam and the capacity of the existing PRVs and piping. Measurements were also made of heat loss from selected sizes of distribution piping.

During the survey a number of potential ECOs for future studies were identified.

1.4.3 Baseline Energy

Proper evaluation of most of the ECOs requires a knowledge of mass and energy flows through the CHPs. To evaluate the cogeneration ECO, the steam loads served by the Area-B CHP are also required. The baseline energy determination includes analyzing the efficiency of the boilers, quantifying auxiliary steam usage for each piece of equipment, determining entering and leaving steam temperatures and pressures, and developing an energy flow diagram for each of the CHPs.

1.4.4 Evaluate Specific ECOs

Each ECO was evaluated individually. The approach to the analysis of each specific ECO is discussed in the relevant section. The cogeneration ECO is discussed in Section 4.0 and the boiler ECOs are discussed in Section 5.0.

1.4.5 Prepare Report

The report for the project covers the two delivery orders. The organization of the report follows the requirements of the SOW for both delivery orders. The Executive Summary follows the Executive Summary Guideline in Annex B of the SOW.

1.5 INVESTMENT COST ESTIMATES

The following sources and assumptions were used in developing cost estimates:

- Equipment and materials costs and manhours were estimated from experience, and using Means 1992 Mechanical Cost Data. Estimates of major equipment costs were obtained from manufacturers and suppliers.

- Labor costs were also taken from Means 1992 Mechanical Cost Data and corrected for the region. The city cost index for the Tri-Cities region is 66.9%. Labor costs are indicated in the following table:

LABOR CATEGORY	LABOR COST ($/manhour)
Steam Fitter	$16.89
Sheet Metal Worker	$16.45
Electrician	$16.19
Skilled Labor	$14.86
General Labor	$12.86

Cost estimates were performed in accordance with Army TM5-800-2, Cost Estimates, Military Construction.

1.6 LIFE CYCLE COST ANALYSES

Life cycle cost analyses were performed using the latest version of the computer program, Life Cycle Cost In Design, (LCCID). The "Energy Conservation Investment Program (ECIP) Guidance" and a letter from CEHSC-FU-M, dated 28 June 1991 were the basis for the life cycle cost analysis.

The LCCID computer program calculates the discounted savings-to-investment ratio (SIR) and simple payback period based on a present worth analysis of the construction cost, projected energy savings, unit energy costs, and other costs associated with the project over the economic life of the project. Other costs include electric demand costs, maintenance costs, and salvage values.

SECTION 2.0

BASELINE ENERGY ANALYSIS

The purpose of this section is to:

- Develop the baseline energy usage from historical data.
- Develop energy costs.

Backup computations and data are contained in Appendix B.

2.1 HISTORICAL ENERGY CONSUMPTION

2.1.1 Electricity

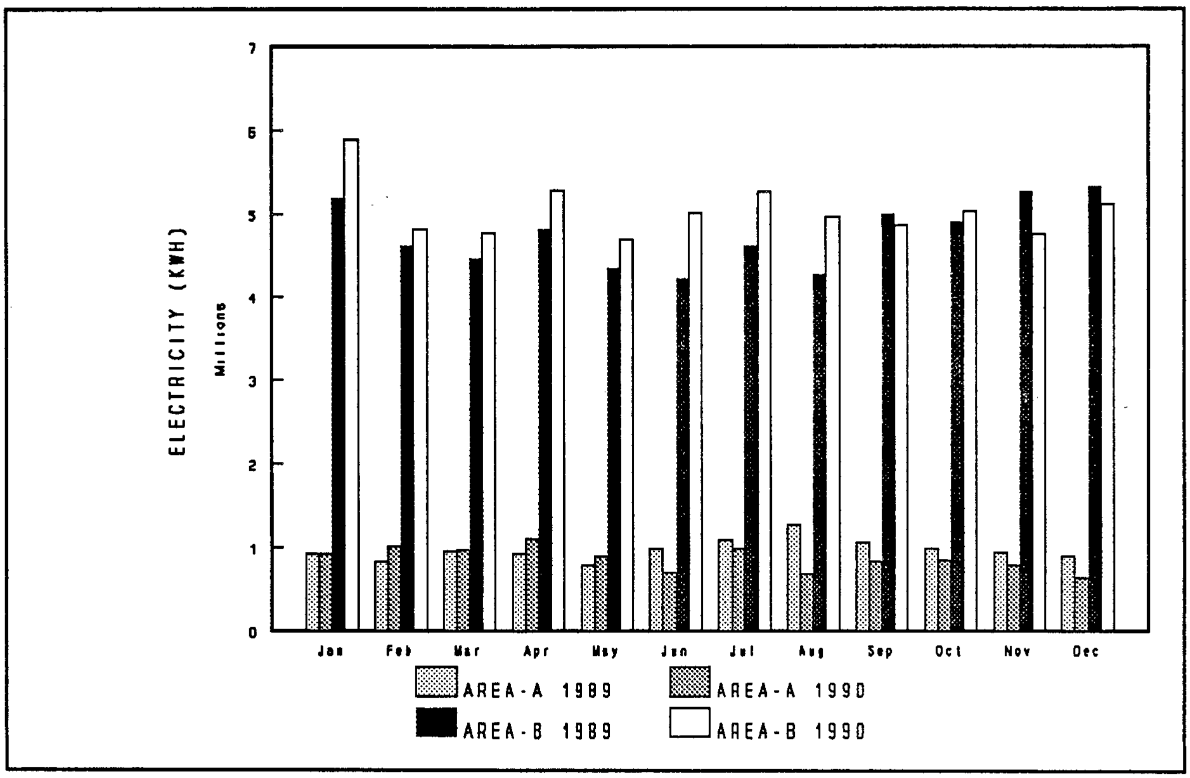


FIGURE 2-1. HAAP HISTORICAL ELECTRICITY USAGE

Electricity usage for the last two calendar years is presented in Figure 2-1 above. As can be seen, Area-B uses about five times as much electricity as Area-A. Combined monthly usage for the two areas averages about 5.8 million kWh, varying from 4.0 to 6.2 million kWh.

The combined electric demand for Area-A and B for the last two calendar years is presented in Figure 2-2 below. Demand data for the individual areas was not available. As can be seen, electric demand varies little on a monthly basis.

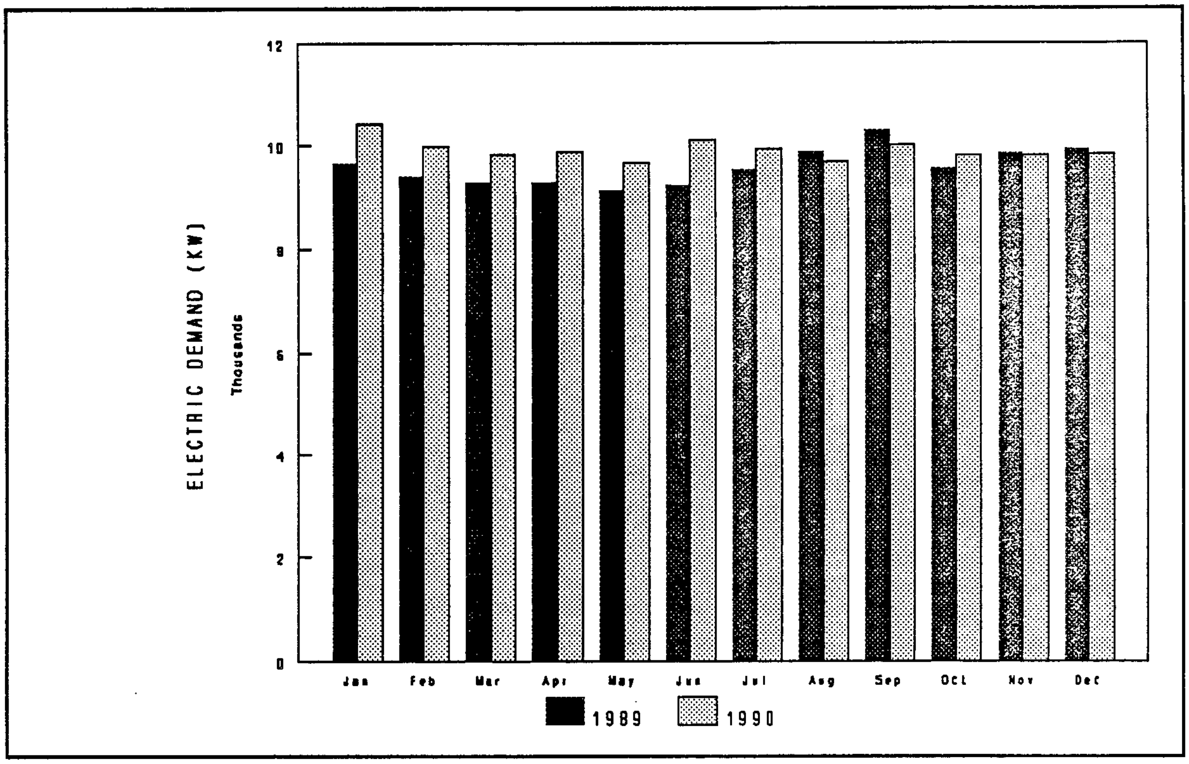


FIGURE 2-2. HAAP HISTORICAL ELECTRICITY DEMAND

2.1.2 Coal

Coal usage for the last two calendar years is presented in Figure 2-3 page 2-3. As can be seen, Area-B uses about twice as much coal as Area-A. Coal usage at Area-A is fairly constant throughout the year with most of the steam going to process loads. Area-B uses more coal during the heating season due to significant space heating loads.

Historical energy consumption data is contained in Appendix B along with metered boiler steam production data. There is a 2 to 4% variation in coal consumption between accounting and utility coal records. Accounting records were selected for use in the analysis because the weight per rail car was considered more accurate than the number of scoops loaded into the coal hoppers at the CHPs.

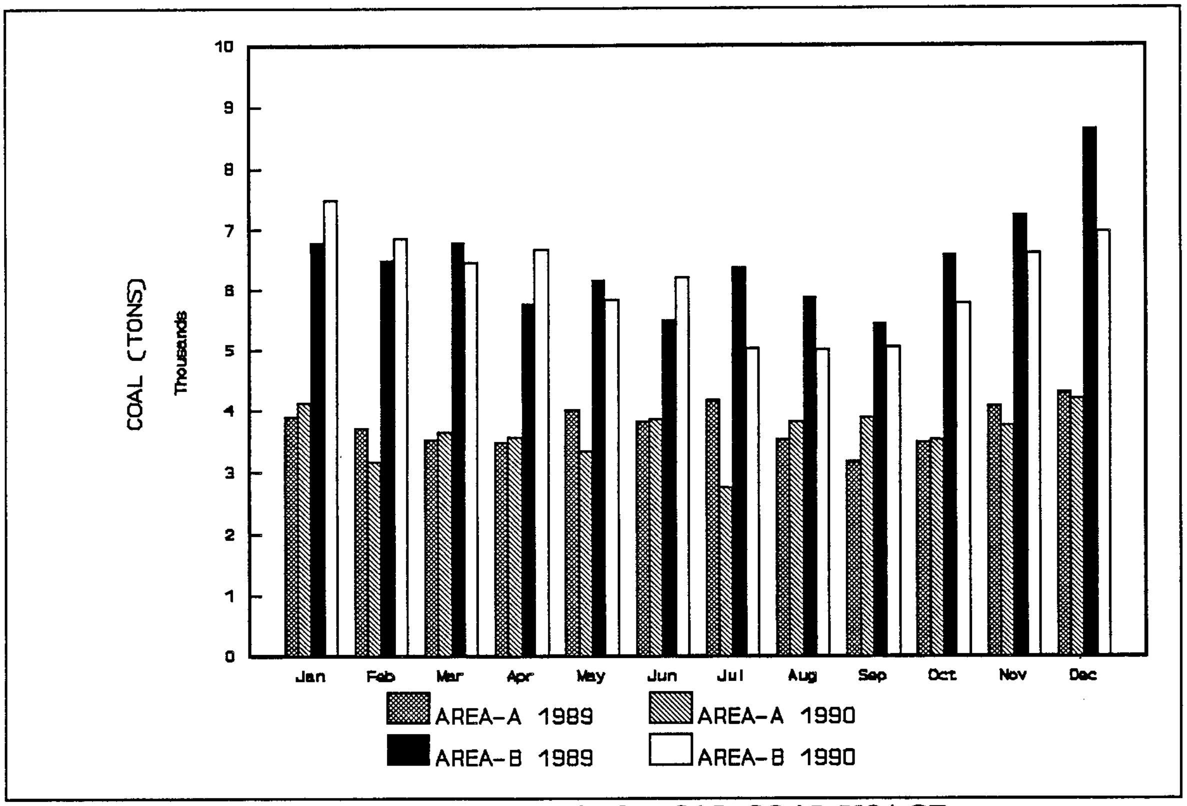


FIGURE 2-3. HAAP HISTORICAL COAL USAGE

2.2 ENERGY COSTS

2.2.1 Electricity

Electricity is provided to HAAP by the Kingsport Power Company by contract. Electricity billings contain the following elements:

- The monthly billing demand rate is \$9.64/kW for the peak demand occurring in the billing period.
- The energy unit price is \$0.01852/kWh for the billing period.
- The monthly service charge is \$1192.
- The fuel adjustment rate is used to adjust the energy charge based on the cost of fuel to Kingsport Power. The fuel adjustment rate varies by month, but has averaged \$0.0024265/kWh deduction over the last two years.
- A 1.5% discount on the total bill is applied for prompt payment.

Applying the average fuel adjustment rate and the 1.5% discount, the resulting incremental electrical demand and average electrical energy charges are \$9.50/kW and \$0.0159/kWh,

respectively. Incremental electrical demand and average electrical energy costs do not include monthly service charges which would not be affected by ECO energy savings.

Dividing the energy charge of $0.0159/kWh by 0.003413 MBtu/kWh gives an average energy cost of $4.67/MBtu.

2.2.2 Coal

Both Area-A and Area-B central heating plants are fired with bituminous coal. A coal gasifier at Area-A also uses bituminous coal. The higher heating value averages about 14,100 Btus per lbm according to laboratory analysis. Present cost of purchased bituminous coal is $35.20 per ton. Anthracite coal has been also used at Area-B for the last two years. HAAP was not charged for anthracite coal which comprised about 14% of the total coal consumed. HAAP has no plans to use anthracite coal in the future. The energy cost of bituminous coal is $1.25/MBtu.

2.2.3 Steam

Coal is used to generate steam in the CHPs. At Area-A an annual average of 932 million pounds of steam was metered exiting the boilers over the last two years at an annual average coal cost of $1,507,680. The resulting energy cost of steam generated by the boilers is $1.62 per thousand pounds of steam. The boilers generate 400 psig, 575°F steam from 228°F feedwater, a change in enthalpy of 1094 Btu/lbm. The resulting energy cost of steam is $1.48/MBtu.

At Area-B an annual average of 1,418 million pounds of steam were metered exiting the boilers over the last two years at an average coal cost of $2,256,500. About 14% of coal consumption at Area-B was anthracite coal for which HAAP was not charged. (In the future anthracite will not be used and additional bituminous coal will need to be purchased.) If HAAP had been charged for all the coal used, the resulting energy cost of steam generated by the boilers would have been $1.82/Mbtu of steam. The boilers generate 300 psig, 525°F steam from 228°F feedwater, which is an enthalpy change of 1074 Btu/lbm. The resulting energy cost of steam is $1.69/MBtu.

2.2.4 Energy Cost Summary

Table 2-1 below summarizes the unit energy costs at HAAP.

TABLE 2-1
UNIT ENERGY COSTS

Energy Source	Unit Cost	Conversion	Energy Cost
Coal	$35.20/ton	14,100 Btu/lbm	$1.25/MBtu
Area-A Steam	$1.62/1000 lbm	1094 Btu/lbm	$1.48/MBtu
Area-B Steam	$1.82/1000 lbm	1074 Btu/lbm	$1.69/MBtu
Electricity Energy Demand	 $0.01595/kWh $9.50/kW/month	3413 Btu/kWh	$4.67/MBtu

Annual energy costs at HAAP are summarized in Table 2-2 below.

TABLE 2-2
ANNUAL ENERGY COSTS

Energy Source	Annual Usage	Equivalent Energy Usage (MBtu)	Unit Energy Cost ($/MBtu)	Annual Energy Cost ($)
ELECTRICITY				
Area-A	11,008,500 kWh	37,572	4.67	175,461
	1,478 kW		9.50**	168,492
Area-B	58,753,500 kWh	200,526	4.67	936,456
	8,268 kW		9.50**	942,552
Subtotal	69,762,000 kWh	238,098		2,222,961
COAL				
Area-A	42,853 tons	1,208,454	1.25	1,510,568
Area-B	74,086 tons	2,089,225	1.25	2,611,531*
Subtotal	116,939 tons	3,297,680		4,122,100*
TOTAL		3,535,778		6,345,061*

* Includes cost for anthracite coal which previously was supplied to HAAP free of charge.
** Monthly demand charges ($/kW).

SECTION 3.0

CENTRAL HEATING PLANT PERFORMANCE

3.1 INTRODUCTION

This study evaluates ECOs for the Area-A and B CHPs. Evaluation of these ECOs requires a detailed knowledge of the mass and energy flows through each CHP. Mass and energy flows through the boilers and CHP are indicated schematically in Figure 3-1 below.

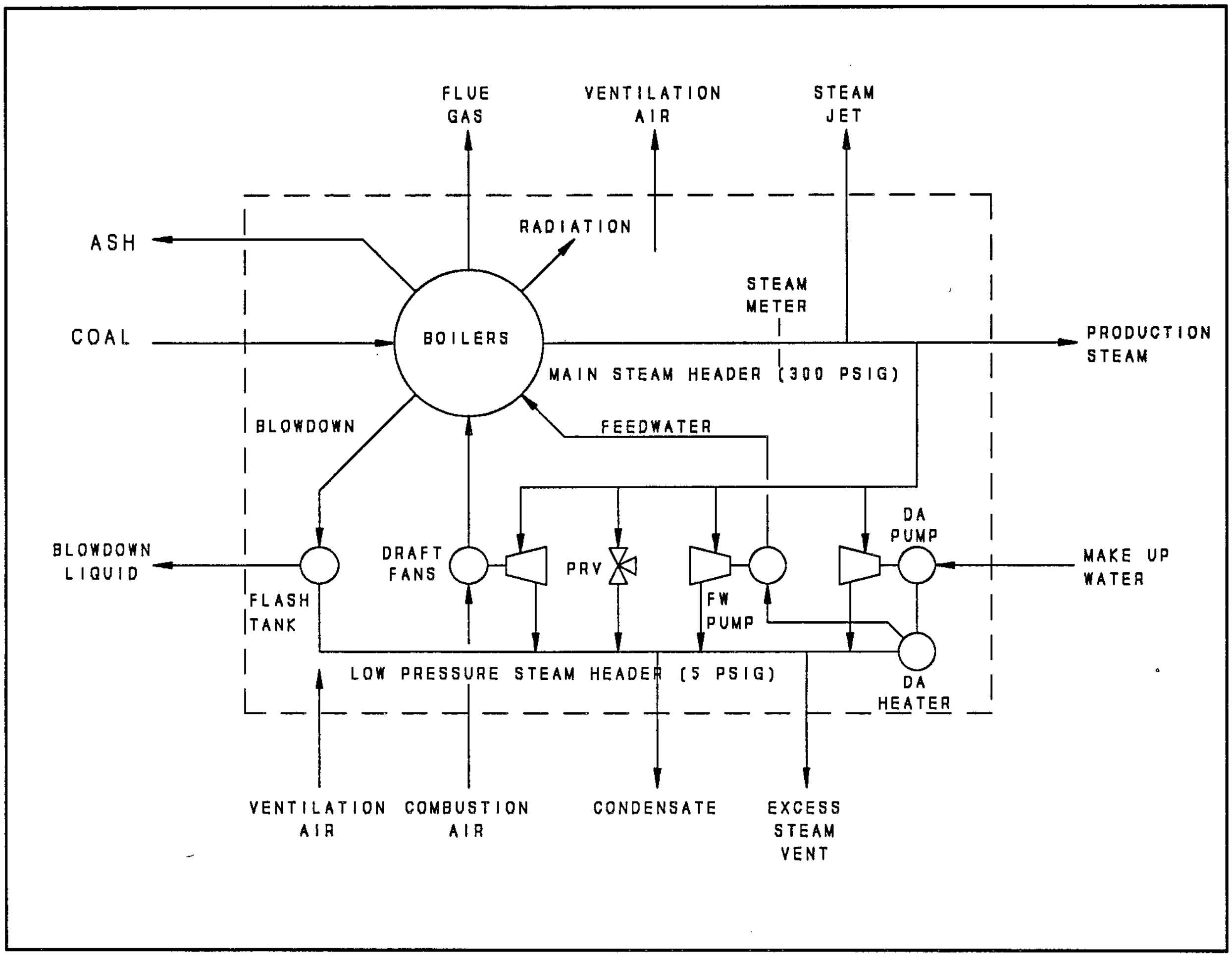


FIGURE 3-1. MASS AND ENERGY FLOW

The approach taken by this study was to develop a computer boiler model which quantifies mass and energy flow for each component shown in Figure 3-1. Performance of individual boilers and the CHPs as a whole may be determined by finding the mass and energy flow of each component entering or leaving the individual boilers, or the CHP as a whole.

The mass and energy balance for the boilers was performed by calculating energy and mass flows of each stream entering or leaving the boilers. Streams leaving each boiler are steam,

flue gas, ash, blowdown water, and heat loss from the boiler skin. In general, the methods presented in the 1989 ASHRAE Fundamentals Handbook, Chapter 15, were used in calculating boiler performance.

In this section, baseline boiler and CHP performance is determined at average operating conditions. Average operating conditions were established based on the average hourly steam production and the average hourly coal usage for calendar years 1989 and 1990.

For the ECO analysis in Section 5.0, the boiler models for Areas-A and B are modified to simulate each ECO modification and to compute annual coal usage with the ECO modification. The difference in coal usage between the baseline model and the modified ECO model is the coal energy saved by the ECO modification.

Most ECOs considered by this study result in a shift in boiler or CHP efficiency and a decrease in coal usage. The computer boiler model provides a quick and accurate assessment of each ECO and its effect on boiler performance.

3.2 AREA-B CENTRAL HEATING PLANT PERFORMANCE

3.2.1 Boiler Description

The boilers in the Area-B CHP were constructed in 1942 and much of the equipment in the CHP is 50 years old. The CHP contains six boilers, four stoker-fired coal and two pulverized coal-fired boilers. Three additional natural gas boilers are housed in an adjacent building. Only the four stoker-fired boilers are operational. The four stoker-fired boilers were all built by Babcock and Wilcox Company and have traveling grate stokers built by Detroit Stoker Company. Table 3-1 on page 3-3 summarizes the characteristics of the nine boilers.

TABLE 3-1
AREA-B BOILERS

Boiler Number	Boiler Type	Maximum Comfortable Firing Rate* (lbm/hr)	Manufacturers Specified Firing Rate (lbm/hr)
1	Stoker Coal	120,000	160,000
2	Stoker Coal	100,000	160,000
3	Stoker Coal	100,000	150,000
4	Stoker Coal	120,000	160,000
5	Pulverized Coal/Oil	150,000	190,000
6	Pulverized Coal/Oil	150,000	190,000
7	Natural Gas	100,000	150,000
8	Natural Gas	100,000	150,000
9	Natural Gas	100,000	150,000

*Maximum comfortable firing rate is maximum rate at which operating personnel operate the boiler without additional manpower.

3.2.2 Boiler Performance

3.2.2.1 Steam Production

Steam produced by each boiler is continuously measured by a steam meter coupled to a pen chart and totalizer. Total steam production is recorded daily and summed for the monthly usage reports. The average hourly steam production for the last two calendar years was 161,872 lbm/hr which is the average operating condition. In 1990, averages in each month varied from 120,000 to 180,000 lbm/hr. Steam usage varies little on a weekly basis. On an hourly basis, there is about a 20% variation from the average over a day. Steam loads are generally supplied by two boilers. Occasionally during cold weather, a third boiler is required.

Peak steam demand at Area-B is estimated at 241,300 lbm/hr based on an outdoor temperature of 9°F and a 20% diversity on the process steam demands. Peak steam demand was calculated in Section 4.0 as part of the cogeneration analysis.

3.2.2.2 Coal Consumption

The amount of coal consumed per pound of steam produced was calculated by dividing the metered steam production by the amount of coal purchased over a two year period. An average of 9.57 pounds of steam was produced for each pound of coal burned over the last two years. Laboratory analysis indicates that energy content of the coals used is 14,100 Btu/lbm.

3.2.2.3 Combustion Air

The amount of combustion air used for the boilers was determined from a boiler efficiency test on Boiler No. 1 and discussions with operating personnel. Flue gas measurements downstream of the precipitators results in readings of 10.5% O_2, and 169 ppm CO, at a 375°F flue gas temperature. The boiler was operating at 80,000 lbm/hr at the time. The boiler plant operators indicate that boilers are typically operated between 8% and 13% O_2 depending on the load. The higher loads allow more efficient operation. Air flow control is set by the operators based on the appearance of the flame. Using data from both Areas-A and B, a curve relating O_2 to percent boiler loading was developed. The curve is shown in Figure 3-2 on the following page. At the average operating condition of 81,000 lbm/hr steam load per boiler, the computer boiler model calculated O_2 at 10.6% and the resulting excess air at 102%. Excess air is the volume of air flowing through the boilers beyond the volume of air required for combustion. At 102% excess air, the volume of air flowing through the boilers is approximately twice that required for combustion.

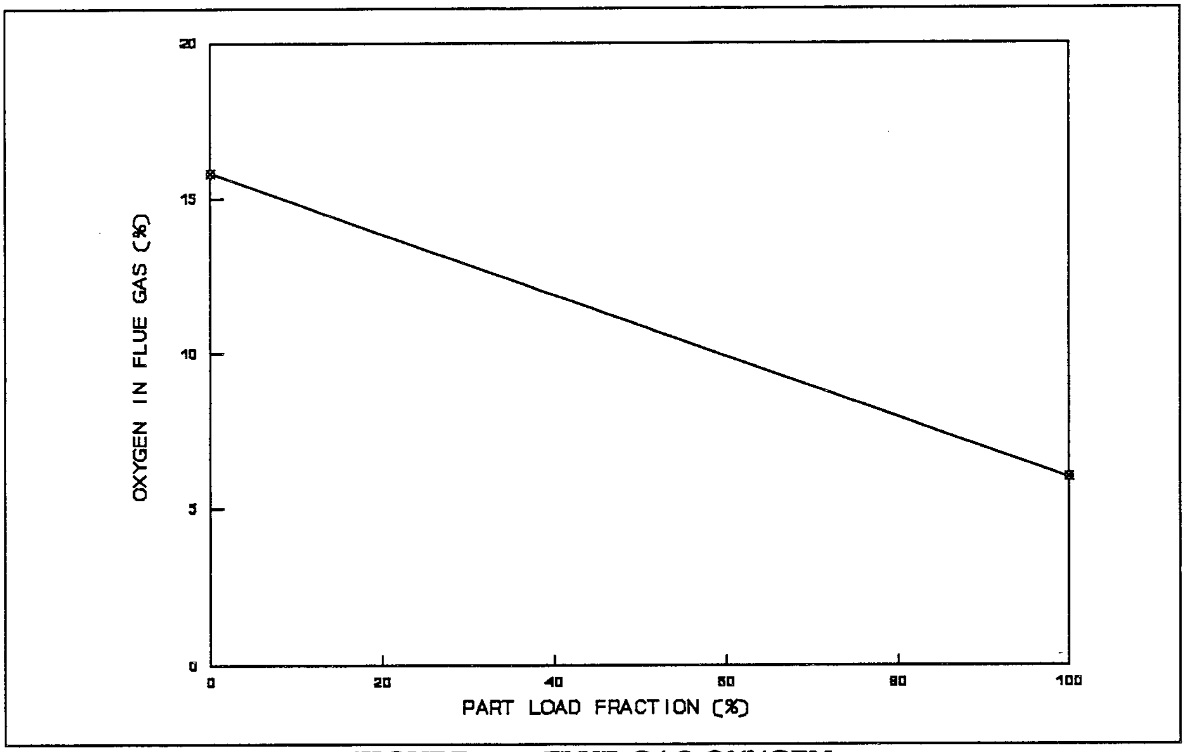


FIGURE 3-2. FLUE GAS OXYGEN

3.2.2.4 Dry Flue Gas Loss

Flue gas losses may be divided into two parts; dry flue loss and flue humidity loss (flue humidity loss is discussed in §3.2.2.5). Dry flue loss is the sensible energy carried away by the air flowing through the boiler. Dry flue loss (Q_{DF}) is calculated as follows:

$$Q_{DF} = (m_2 Cp_2 T_2) - (m_1 Cp_1 T_1) .$$

where,

- m_2 = the dry mass flow rate of combustion products leaving the boiler and is equal to the dry mass of combustion air entering the boiler plus the dry mass of the combustion products,
- Cp_2 = the specific heat of combustion products assumed to be 0.248,
- T_2 = the flue gas temperature measured at 375°F,
- m_1 = the dry mass flow rate of combustion air entering the boiler determined from the measured oxygen content in the flue gas and the theoretical air required for stoichiometric combustion,
- Cp_1 = the specific heat of combustion air which is 0.240, and
- T_1 = the entering combustion air temperature.

At average operating conditions, the computer boiler model calculated dry flue gas loss at 13.4% of the fuel input to the boiler.

3.2.2.5 Flue Humidity Loss

Flue humidity loss is the water vapor added to the flue gas by the products of combustion, plus the additional heat loss due to water vapor in combustion air. Flue humidity loss is dependant on the amount of hydrogen in the coal and the flue gas temperature. Hydrogen content in the coal was estimated at 5% which is typical for coal in the region. At the average operating condition, flue humidity loss was determined to be 3.9% of the fuel input to the boiler.

3.2.2.6 Feedwater

Boiler feedwater is heated to 228°F in the deaerating (DA) heater prior to entering the boiler. The feedwater rate is equal to the boiler steam production rate plus the blowdown flow rate.

3.2.2.7 Blowdown

The boilers are equipped with continuous top blowdown systems which discharge into a common flash tank. Flash steam is routed into the low pressure header for deaerating heating and the condensate is sent to waste treatment. The top blowdown rate was measured by partially draining the flash tank and then measuring the time required for it to refill. With the boilers operating at 167,000 lbm/hr, the blowdown rate was measured at 4,111 lbm/hr or about 2.5% of the steam rate. The blowdown rate is manually controlled and was assumed to remain at 2.5% of the steam rate over the normal boiler operating range. Bottom blowdown is performed intermittently and consumes a negligible amount of energy. At average operating conditions, blowdown energy loss is 0.7% of the fuel input to the boiler.

3.2.2.8 Radiation

Radiation is radiant and convective heat loss from the surface of the boiler. Radiation is typically 1 to 2% of peak boiler capacity and remains constant over the firing range. Radiation was assumed to be 1% of peak boiler capacity. The resulting radiation loss is 1.65 Mbh. Radiation loss does not vary with the steam production rate of the boiler, but remains constant. At average operating conditions, radiation loss is 1.4% of the fuel input to the boiler.

3.2.2.9 Combustion Loss

The remaining losses from the boiler were assumed to be unburned carbon in the ash and were termed combustion loss. Combustion loss was calculated by subtracting calculated losses from the total loss in the computer boiler model. Most of the ash from the boilers is

likely has a high carbon content. Bottom ash is gray and likely contains little carbon although there are pieces of coal in it which fall off the grate. At average operating conditions, combustion losses were estimated to be 8.1% of the fuel input and were based on the measured fuel input less the measured steam output and other boiler losses.

3.2.2.10 Economizer

Boilers are equipped with economizers which use hot flue gas exiting the boiler to pre-heat boiler feedwater. At average operating conditions, hot flue gas at 480°F is used to raise feedwater temperature from 228°F to 283°F. For the boiler analysis presented in this report, the economizer is considered part of the boiler. Thus the energy savings provided by the economizer are a part of the boiler efficiency determination.

3.2.2.11 Boiler Efficiency

Figure 3-3 on page 3-8 summarizes boiler performance of Area-B boilers at average operating conditions. As can be seen, energy output from the boiler in the form of steam is 72.5% of the fuel input; which is by definition the boiler efficiency. Dry flue loss and combustion loss are 13.4% and 8.1% of the fuel input, respectively. The remaining 6.0% is blowdown, radiation, and flue humidity loss.

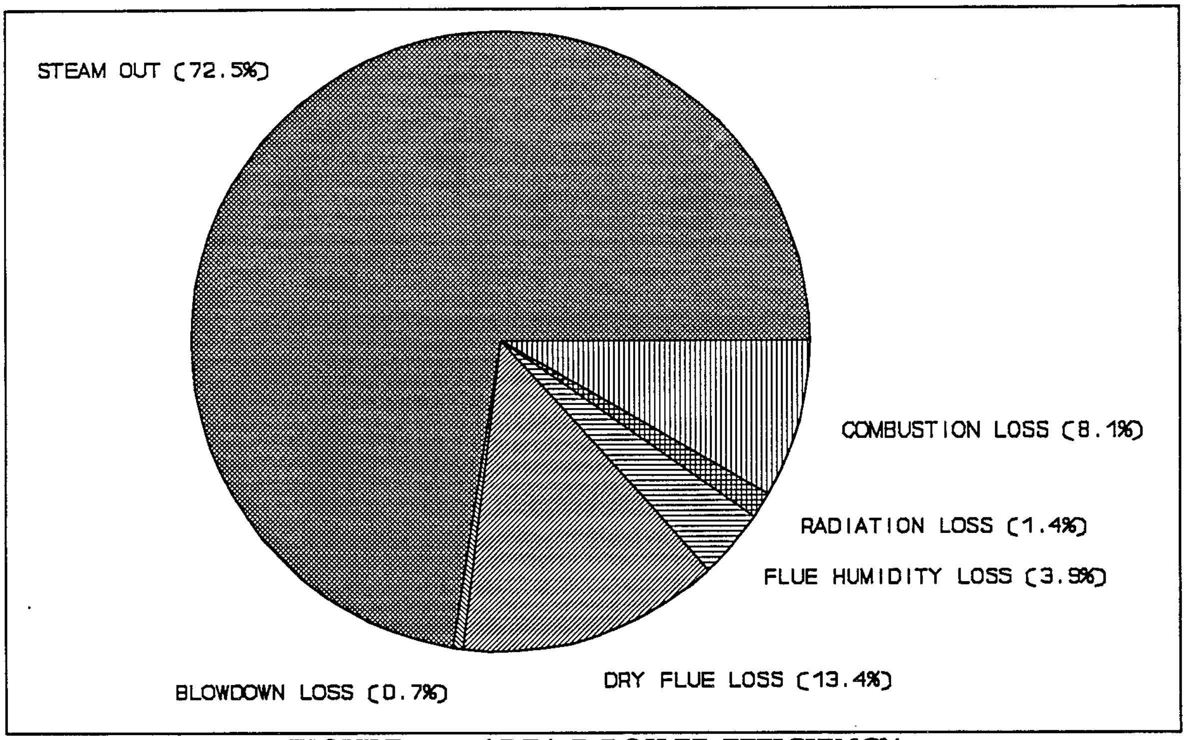


FIGURE 3-3. AREA-B BOILER EFFICIENCY

3.2.3 Central Heating Plant Performance

The Area-B CHP uses a portion of the steam produced by the boilers to drive pumps and fans associated with the boilers, for deaerating boiler feed water, and for ash transport. This section describes CHP auxiliary equipment and characterizes mass and energy flows through the CHP. These flows are presented schematically in Figure 3-1 on page 3-1.

3.2.3.1 Draft Fans

Each boiler has a forced draft and induced draft fan on the ground floor. Both fans are driven by a steam turbine off a common shaft. New turbines were installed in 1980 as part of a project to install electrostatic precipitators. It was reported in the 1983 EEAP report, prepared for the HAAP by A.M. Kinney, Inc., that the induced draft fans have a capacity less than the boilers and, therefore, limit the performance of the boilers to slightly below that specified by the manufacturer. The draft fan steam turbines have the following characteristics:

Manufacturer: .... Skinner Engine Company
Model: S-28-3
Serial Number: 75ST10148
Horsepower: 550
Steam rate: .... 21.6 lbm/hr/hp
Inlet Pressure: .... 300 psig

Inlet Temperature: . . . . 525°F
Exhaust Pressure: . . . . 5 psig
RPM: 4200
Maximum Casing Pressure: . . . . 75 psig

The steam demand of the draft fan steam turbines was calculated as follows:

- Air flow rates at the rated boiler peak steam production was calculated using the computer boiler model.
- The draft fan steam turbine was assumed to be fully loaded at 550 hp at the rated boiler peak steam production.
- The part load draft fan power required was calculated using a typical inlet vane performance curve and the 550 hp peak horsepower.
- The peak steam rate of the draft fan steam turbine was provided by the manufacture.
- Using the standard turbine characteristic of 60% steam rate at 50% part load, the steam rate at the part load condition was calculated.
- The steam demand of the steam turbine is then the part load steam rate times the part load fan power required.

3.2.3.2 Deaerator (DA) Pump

A common DA pump serves all of the boilers. The DA pump is rated at 1750 gpm at a head of 185 feet. The primary DA pump is powered by a steam turbine installed in 1966. An electric DA pump is installed in parallel as a standby pump. The DA pump steam turbine has the following characteristics:

Manufacture: . . . . General Electric
Model: DP-25
Serial Number: 123274
Horsepower: 80
Steam rate: . . . . 60.7 lbm/hr/hp
Inlet Pressure: . . . . 275 psig
Inlet Temperature: . . . . 525°F
Exhaust Pressure: . . . . 25 psig
RPM: 1750

Steam demand for the DA pump steam turbine was calculated following the same procedure used for the fan turbines in §3.2.3.1, except that the pump efficiency curve was used in place of the inlet vane curve.

At average operating conditions, the DA pump is quite inefficient. The DA pump is designed to operate at 1750 gpm, but the average flow rate through the pump is 282 gpm. The resulting pump efficiency is approximately 40%.

3.2.3.3 Feedwater (FW) Pumps

Four feedwater pumps serve the boilers. The feedwater pumps are driven by steam turbines. One feedwater pump has the capacity to serve two boilers. The feedwater pump steam turbines have the following characteristics:

FW Pump Number: .	1 through 3	FW Pump Number: . .	4
Manufacturer:	General Electric	Manufacturer:	Terry Dresser Rand
Model:	DP-20	Model:	DO-292
Serial Number:	61592	Serial Number:	42788A
Horsepower:	265	Horsepower:	135
Steam rate:	35.5 lbm/hr/hp	Steam rate:	33.4 lbm/hr/hp
Inlet Pressure:	275 psig	Inlet Pressure:	300 psig
Inlet Temperature: . .	525°F	Inlet Temperature: . . .	525°F
Exhaust Pressure: . . .	25 psig	Exhaust Pressure: . . .	25 psig
RPM:	3550	RPM:	3600

Feedwater pump No. 4 is normally used because it is sized closer to current CHP steam production rates than FW pumps 1-3. Steam demand for the feedwater pump steam turbine was calculated following the same procedure used for the DA pump turbines in §3.2.3.2. A pump curve could not be located for this pump. A pump efficiency of 70% was assumed based on performance of a similar pump operating at the same part load condition.

3.2.3.4 Blowdown Flash Tank

Flash steam from boiler blowdown water is captured in the flash tank and routed to the DA heater. About 21% of the blowdown water is flashed into steam. Blowdown liquid is discharged into to the wastewater system.

3.2.3.5 Deaerating (DA) Heater

In the DA heater, low pressure (5 psig) steam is used to heat and deaerate boiler feedwater. Since no condensate is returned to the boiler plant, all of the boiler feedwater must be heated from ambient temperatures to 228°F, which is a significant heating load. Since boiler make-up water is drawn from the river, stored in a reservoir, and then in an outdoor tank; make-up water temperature was assumed to be equal to ambient air temperature. The annual average ambient air temperature at HAAP is 56°F. The average ground temperature in Tennessee is 60°F which is the source of the water in the river. However, surface water temperatures typically follow average ambient air temperatures. The low pressure steam condenses in the DA heater and contributes about 15% of the mass of water exiting the heater.

3.2.3.6 Low Pressure Steam Header

The low pressure (5 psig) steam header is fed by the exhaust from the turbines driving the draft fans, feedwater pump, and DA pump, and from the blowdown flash tank. The only user of low pressure steam is the DA heater. If insufficient steam is available for the DA heater, additional 300 psig steam is fed to the low pressure steam header through a pressure reducing station. If excess steam is present in the low pressure steam header, it is vented to the atmosphere.

Figure 3-4 below shows the steam balance in the low pressure steam header calculated for each month of the year. At low steam demand during the summer, excess steam is present due to part load inefficiency of the pumps, fans, and turbines. At high steam demand during the winter, the low pressure steam header is fed additional steam from the 300 psig main. Steam venting from the CHP is a visible energy loss, but its magnitude is small relative to the annual CHP steam production.

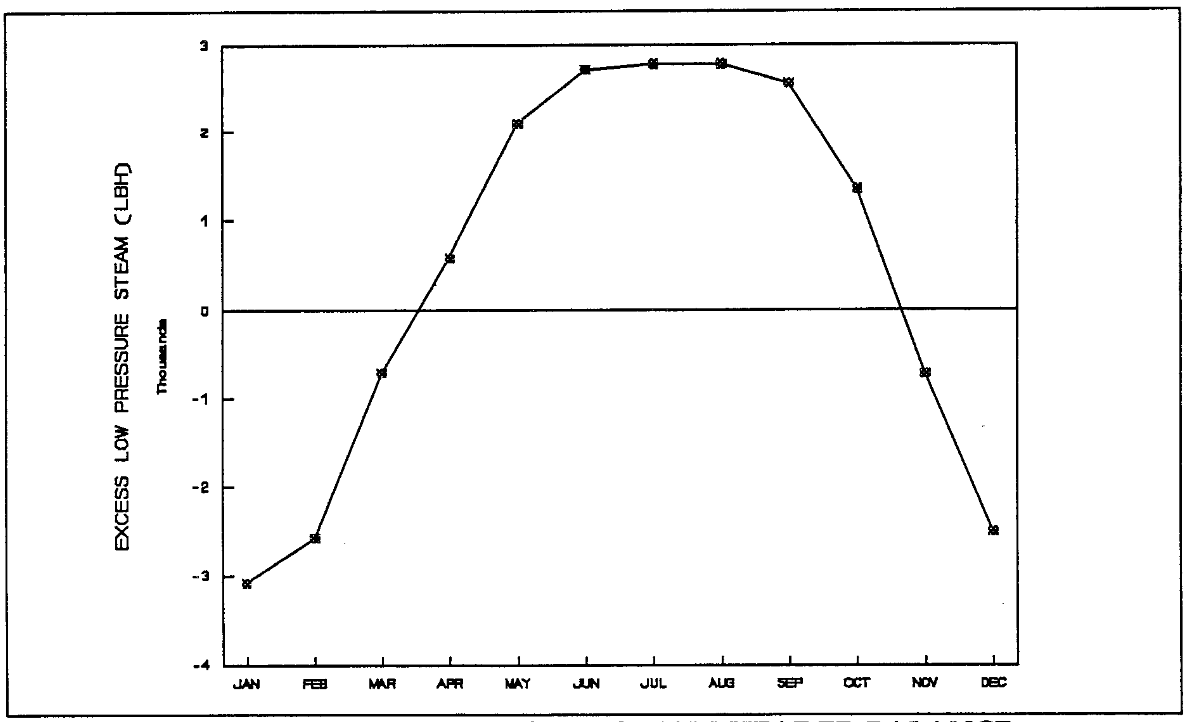


FIGURE 3-4. LOW PRESSURE STEAM HEADER BALANCE

3.2.3.7 Steam Traps

Steam traps on the low pressure steam header and at the steam turbines used to drive the draft fans, DA pump and feedwater pumps, remove condensate and discharge it into the wastewater drain system. The amount of condensate generated by each component was estimated as follows:

- Turbines driving the draft fans have exiting steam quality of 99.1%, according to the manufacturer. The resulting condensate generation at average boiler operating conditions with two draft fan turbines operating is a total of 175 lbm/hr.

- Turbines driving the DA pump discharge superheated steam with no condensate generation.

- Turbines driving the feedwater pumps discharge superheated steam with no condensate generation.

- The high pressure (300 psig) steam header contains superheated steam with no condensate generation from pipe heat loss.

- The low pressure (5 psig) steam header also likely contains steam which is slightly superheated. The DA pump and feedwater pump turbines discharge superheated steam into the low pressure steam header. Little or no condensate generation is expected.

Considering energy and mass flow through the plant, condensate losses are insignificant.

3.2.3.8 Steam Jet

A steam jet vacuum system is used to move fly ash from the cyclone and precipitators to a collection bin. On the average, the steam jet operates 4 hours per day. During operation the steam jet cycles on and off as various valves and dump gates are cycled. The steam jet runs about 75% of the time during operating cycles reducing actual running time to 3 hours per day. During operation the steam jet is estimated to use 7,455 lbm/hr of 300 psig steam. Operating only 3 hours per day, the daily average is 932 lbm/hr.

3.2.3.9 Central Heating Plant Efficiency

The distribution of steam flow in the Area-B CHP is presented graphically in Figure 3-5 on page 3-13. Approximately 83.5% of the steam produced by the boilers is sent to the distribution system. The remaining 16.5% is used within the CHP. The largest steam load within the CHP is the draft fan steam turbines which consume 11.9% of the steam generated.

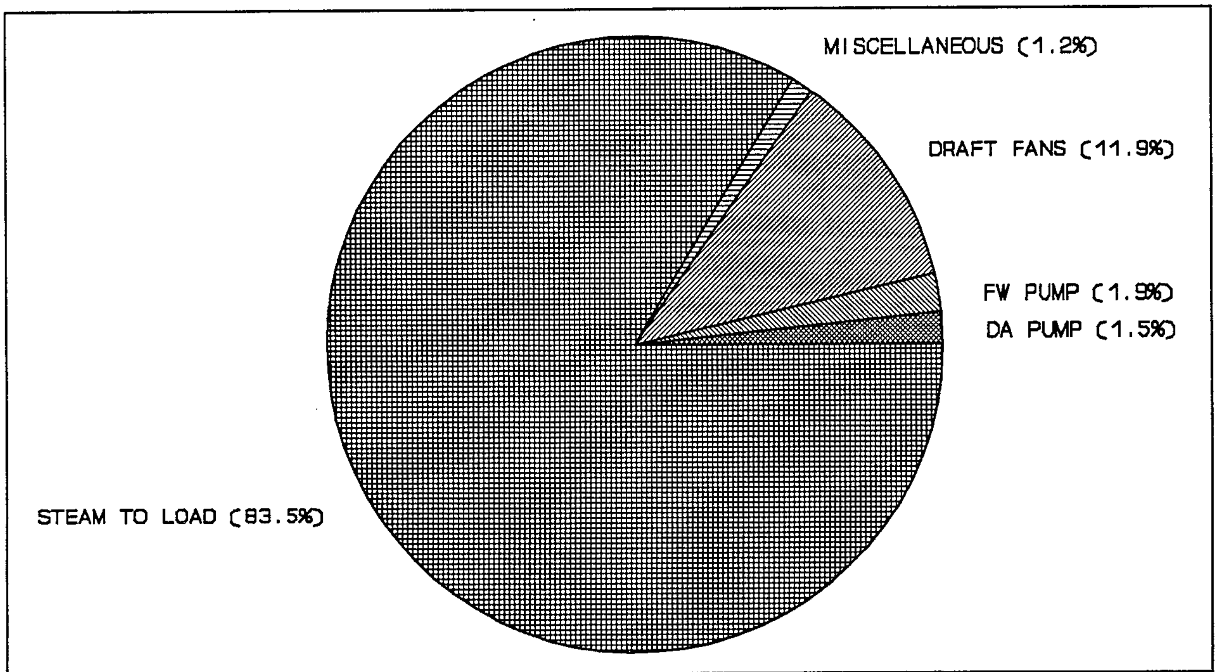


FIGURE 3-5. DISTRIBUTION OF CHP STEAM FLOW AT AREA-B

Most of the steam used by the CHP is not lost, but is first used in steam turbines driving the draft fans, feedwater pump, and DA pump, and then to heat boiler feedwater in the DA heater. Not only is most of the energy in the steam recovered, the mass is also recovered and recirculated through the boilers via the DA heater. At average operating conditions, turbine steam usage and DA heater steam load are closely matched.

The Area-B CHP efficiency at average operating conditions was calculated by the computer boiler model to be 70.5%. CHP efficiency is defined as the energy production of the CHP divided by the coal energy consumed. The energy production of the CHP is the energy leaving the CHP in the form of steam delivered to the steam distribution system less the energy entering the CHP in the make-up water. Energy losses from the CHP include all of the boiler losses with the exception of the flash steam recovered in the blowdown flash tank. The remaining CHP losses are the steam jets used for ash transport, excess steam vented from the low pressure steam header, condensate loss, and heat loss from pipes and equipment.

3.3 AREA-A CENTRAL HEATING PLANT PERFORMANCE

The boilers, support equipment, and layout at the Area-A CHP is almost identical to the Area-B CHP with the following notable exceptions:

- The Area-A CHP generates steam at 400 psig.
- Condensate from Area-A process loads is returned to the CHP.

- The Area-A CHP DA pump is powered by an electric motor rather than a steam turbine.

3.3.1 Boiler Description

The boilers in the Area-A CHP were constructed in 1943 and much of the equipment in the CHP is nearly 50 years old. The CHP contains seven boilers, six stoker-fired coal and one pulverized coal-fired boiler. The six stoker-fired boilers were built by Springfield Boiler Company and Hoffman Combustion Engineering Company. Table 3-2 below summarizes the characteristics of the seven boilers.

TABLE 3-2
AREA-A BOILERS

Boiler Number	Boiler Type	Maximum Comfortable Firing Rate* (lbm/hr)	Manufacturers Specified Firing Rate (lbm/hr)
1	Stoker Coal	100,000	130,000
2	Stoker Coal	100,000	130,000
3	Stoker Coal	100,000	130,000
4	Stoker Coal	100,000	130,000
5	Stoker Coal	100,000	190,000
6	Stoker Coal	150,000	130,000
7	Pulverized Coal	190,000	170,000

*Maximum comfortable firing rate is maximum rate at which operating personnel will operate the boilers without additional manpower.

3.3.2 Boiler Performance

3.3.2.1 Steam Production

Steam produced by each boiler is continuously measured by a steam meter coupled to a pen chart and electronic data system. Total steam production is recorded daily and summed for the monthly usage reports. The average hourly steam production for the last two calendar years was 106,300 lbm/hr, which is the average operating condition. In 1990, averages in each month varied from 82,000 to 136,000 lbm/hr. Steam usage varies little on a weekly basis. Steam loads are generally supplied by two boilers.

Peak steam demand at Area-A is estimated at 162,700 lbm/hr based on a 20% diversity factor applied to the peak month over the last two years.

3.3.2.2 Coal Consumption

The amount of coal consumed per pound of steam produced was calculated by dividing the metered steam production by the amount of coal purchased over a two year period. An average of 10.7 pounds of steam was produced for each pound of coal burned over the last two years. Laboratory analysis indicates that energy content of the coal used is 14,100 Btu/lbm.

3.3.2.3 Combustion Air

The Area-A boilers are equipped with an electronic control and instrumentation system including O_2 trim. The O_2 trim air flow control is set by the operators based on the appearance of the flame. Boiler logs indicate that both the Area-A and Area-B boilers operate with approximately the same amount of excess air. Both Area-A and Area-B boilers have been retrofitted with identical overfire air systems to improve combustion efficiency. The curve relating oxygen content in the flue gas to part load developed for Area-B boilers was based on data from both Areas-A and B, and was also used for the Area-A boilers.

3.3.2.4 Dry Flue Gas Loss

Dry flue gas loss was determined as described in the Area-B boiler analysis in §3.2.2.4. At average operating conditions, the computer boiler model calculated dry flue gas loss at 15.2% of the fuel input to the boiler.

3.3.2.5 Flue Humidity Loss

Flue humidity loss was based on the Hydrogen content in the fuel as described in the Area-B analysis. At average operating conditions, the computer boiler model calculated flue humidity loss at 3.9% of the fuel input to the boiler.

3.3.2.6 Feedwater

Boiler feedwater is heated to approximately 228°F in the DA heater prior to entering the boiler. Unlike Area-B, which does not return condensate to the CHP, Area-A returns about 60% of the condensate. The result is the amount of low pressure steam required for the DA heater is significantly lower than for Area-B.

3.3.2.7 Blowdown

The blowdown rate for the Area-A CHP was assumed to be the same as that measured at Area-B. The feedwater treatment system at both Areas-A and B are the same design; the same blowdown rates will likely be required. At average operating conditions, the computer boiler model calculated blowdown energy loss at 0.8% of the fuel input to the boiler.

3.3.2.8 Radiation

Boiler radiation was also assumed to be the same for boilers in both Areas A and B at 1.65 MBh. The boilers in both Areas-A and B are the same size and construction. At average operating conditions, the computer boiler model calculated radiation loss at 2.2% of the fuel input to the boiler.

3.3.2.9 Combustion Loss

A major difference in the Area-A and Area-B CHPs is the combustion losses which is unburned carbon in the ash. Area-B disposes of almost twice as much fly ash per ton of coal burned as Area-A. Combustion losses for Area-A were estimated to be zero based on the measured fuel input less the measured steam output and other boiler losses. Combustion losses appear to account for the bulk of the difference in performance of the two CHPs.

3.3.2.10 Economizer

Measurements and observations in the field indicate that the economizers at each CHP are performing approximately the same.

3.3.2.11 Boiler Efficiency

Figure 3-6 on page 3-16 summarizes boiler performance of Area-A boilers calculated by the computer boiler model at average operating conditions. As can be seen, energy output from the boiler in the form of steam is 77.9% of the fuel input; which is by definition the boiler efficiency. Dry flue loss and flue humidity loss are 15.2% and 3.9% of the fuel input, respectively. The remaining 3.0% is blowdown, radiation, and combustion loss.

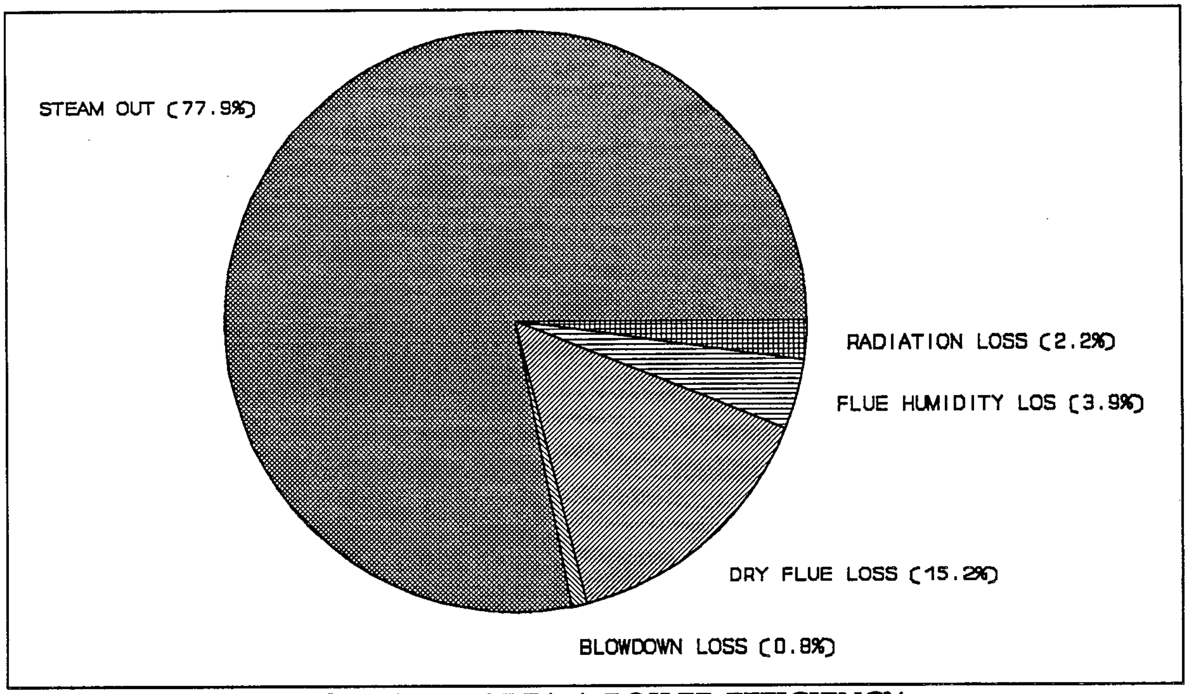


FIGURE 3-6. AREA-A BOILER EFFICIENCY

3.3.3 Central Heating Plant Performance

The CHP uses a portion of the steam produced by the boilers to drive pumps and fans associated with the boilers, and for ash transport. This section describes CHP auxiliary equipment and characterizes mass and energy flows through the CHP.

3.3.3.1 Steam Turbines

Each boiler has a forced draft and induced draft fan on the ground floor. Both fans are driven by a steam turbine off a common shaft. The feedwater pumps are also driven by steam turbines. Turbine steam rates were determined by correcting the Area-B steam rates for the higher pressure at Area-A.

3.3.3.2 Blowdown Flash Tank

Flash steam from boiler blowdown is captured in the flash tank and routed to the DA heater. Approximately 24% of the blowdown water is flashed to steam. Blowdown liquid is discharged into the wastewater system.

3.3.3.3 Deaerating (DA) Heaters

In the DA heaters, low pressure (5 psig) steam is used to heat and deaerate boiler feedwater. Since approximately 60% of the condensate is returned to the boiler plant, DA heating requires

much less steam than Area-B. The low pressure steam condenses in the DA heater and contributes about 15% of the mass of water exiting the heater.

3.3.3.4 Low Pressure Steam Header

The low pressure (5 psig) steam header is fed by the exhaust from the turbines driving the draft fans and feedwater pump. The blowdown flash tank also contributes low pressure steam to the header. The only user of low pressure steam is the DA heater. If insufficient steam is available for the DA heater, additional 400 psig steam is fed to the low pressure header through a pressure reduction station. If excess steam is present in the header, it is vented to the atmosphere. Analysis indicates that at average operating conditions 8,607 lbm/hr of excess steam is vented.

3.3.3.5 Steam Traps

Analysis of the Area-B CHP indicates that condensate generation within the CHP is insignificant. This also is true for the Area-A CHP.

3.3.3.6 Steam Jet

A steam jet vacuum system is used to move fly ash from the cyclone and precipitators to a collection bin. On the average, the steam jet operates 2 hours per day. During operation the steam jet cycles on and off as various valves and dump gates are cycled. The steam jet runs about 75% of the time during operating cycle reducing actual running time to 1.5 hours per day. During operation the steam jet is estimated to use 7,455 lbm/hr of 300 psig steam. Operating only 1.5 hours per day, the daily average is 466 lbm/hr.

3.3.3.7 Central Heating Plant Efficiency

The Area-A CHP efficiency at average operating conditions was calculated by the model to be 70.3%. CHP efficiency is defined as the energy production of the CHP divided by the coal energy consumed. The energy production of the CHP is the energy leaving the CHP in the form of steam delivered to the steam distribution system less the energy entering the CHP in the make-up water. Energy losses from the CHP include all of the boiler losses with the exception of the flash steam recovered in the blowdown flash tank. The remaining CHP losses are the steam jets used for ash transport, excess steam vented from the low pressure steam header, condensate loss, and heat loss from pipes and equipment.

SECTION 4.0

COGENERATION

4.1 ECO CONCEPT

Steam is currently distributed from the CHP to Area-B for space heating and process loads at 300 psig and 525°F. This ECO consists of installing a steam turbine-generator for Area-B. A new steam turbine-generator would accept steam at 300 psig, generate a portion of the electricity required by Area-B, and exhaust the steam to the distribution system at a lower pressure for space heating and process loads.

The system would use a back-pressure steam turbine to reduce steam pressure from the 300 psig produced by the boilers to the pressure required for space heating and process loads. Electricity generated would be fed back into the Area-B grid for use on site.

Steam from the proposed steam turbine-generator would serve all of Area-B with reduced pressure steam, with the exception of Buildings B-6 and 334 which require 300 psig steam (see Figure 4-1 on page 4-3). These buildings would continue to be supplied with 300 psig steam through a takeoff upstream of the proposed steam turbine-generator. A line to bypass 300 psig steam around the turbine would be required to supply steam during mobilization.

The recommended location for the steam turbine-generator is adjacent to the Area-B CHP on the north side between the two major steam distribution mains serving Area-B.

4.2 PREVIOUS STUDIES

4.2.1 <u>HDC Engineering Report E88-0007, Cogeneration of Steam & Electricity at HAAP Using No. 5 Boiler, Building 200, Area B</u>

A brief study was performed in 1988 by HDC to evaluate the possible use of a steam turbine-generator in conjunction with reactivation of the No. 5 Boiler. The No. 5 Boiler is a pulverized-coal boiler capable of operating at 500 psig. The existing operational stoker-coal boilers are limited to 300 psig operation. This study addressed the concept of adding a steam turbine-generator which would reduce steam from 500 to 300 psig. The exit pressure at 300 psig is the same steam distribution pressure now used at Area-B.

The results of that study indicated that cogeneration was an economically attractive alternative to present stoker-fired boiler operation. The economics were based on projected savings in fuel purchase costs with lower grade coal, savings in coal consumption due to 5-10% higher boiler efficiency, and savings in cost for electricity. Annual energy cost savings were estimated at $673,183. Investment costs were estimated at $1,350,000, but did not include the $5,200,000 required for reactivation of the No. 5 Boiler.

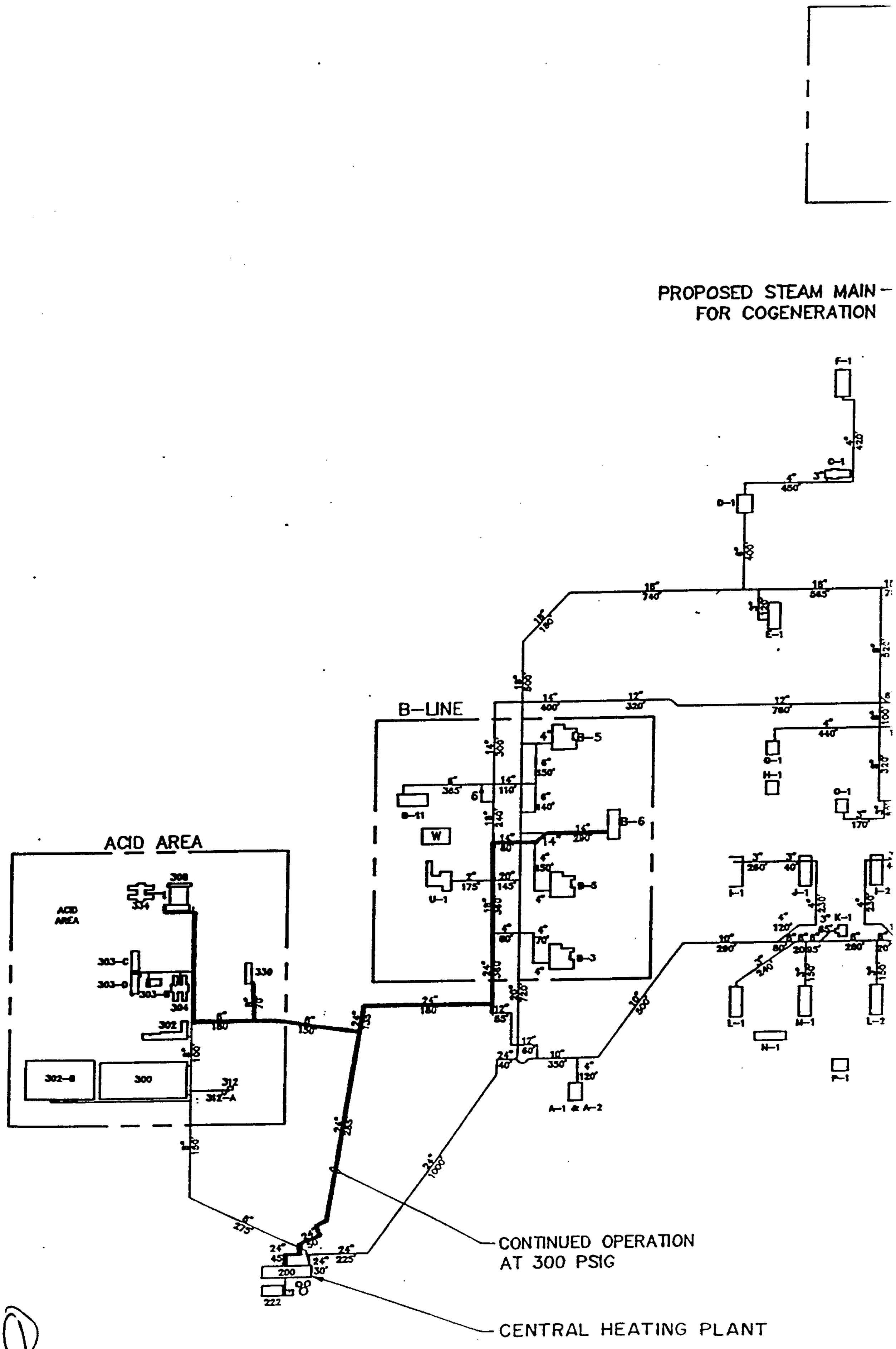
4.2.2 Kinney EEAP Report

The 1983 EEAP report prepared for the HAAP by A.M. Kinney, Inc. included an analysis of cogeneration options. This study examined the use of steam turbines to reduce steam pressure from the existing 300 psig in the distribution piping to 30 psig which is the end use steam pressure in most cases. Four different options were examined, three of which required installation of low pressure steam distribution systems or conversion of high pressure distribution systems. Economic analysis was performed on the two most promising options:

- A small 405 kW steam turbine-generator located in Building B-6 which served the existing low pressure distribution system for the other Area-B buildings. Annual energy cost savings were estimated at $94,800. Investment costs were estimated at $175,000.

- A large 2,105 kW steam turbine-generator located in Building B-6 which served both the existing low pressure distribution system for the B-line buildings and the remainder of the production area. In addition to the turbine-generator, about 7,000 feet of new steam piping would be required. Annual energy cost savings were estimated at $489,800. Investment costs were estimated at $1,342,000.

Based on this study a 400 kW steam turbine-generator was installed in Building B-6.


PROPOSED STEAM MAIN — FOR COGENERATION
B—LINE
ACID AREA
CONTINUED OPERATION AT 300 PSIG
CENTRAL HEATING PLANT
300
302-B
302
303-C
303-D
304
308
312
312-A
330
200
222
A-1 & A-2
B-3
B-5
B-6
B-11
U-1
W
F-1
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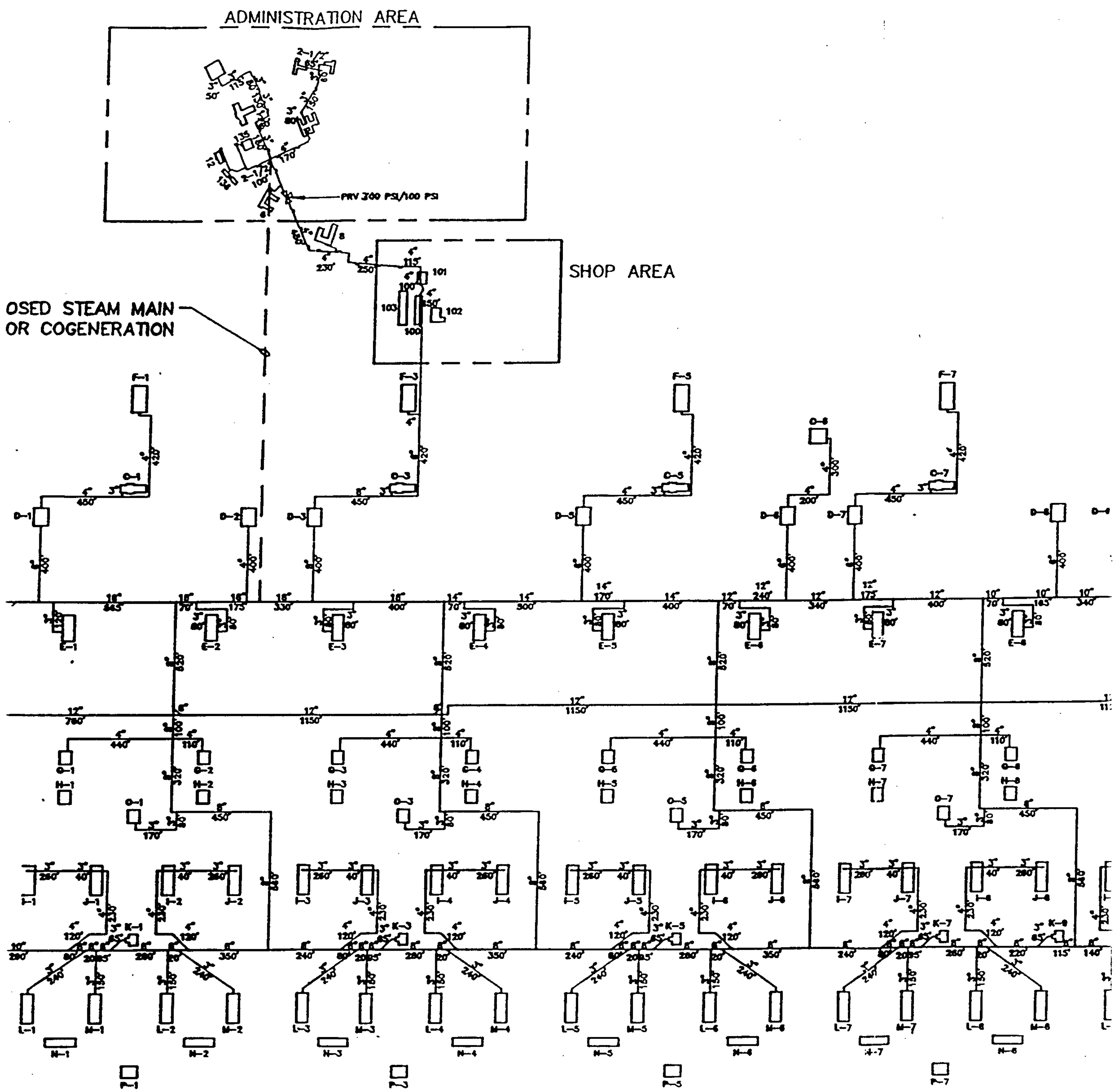

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FIGUR
AREA-B STEAM I
SYSTEM SCI

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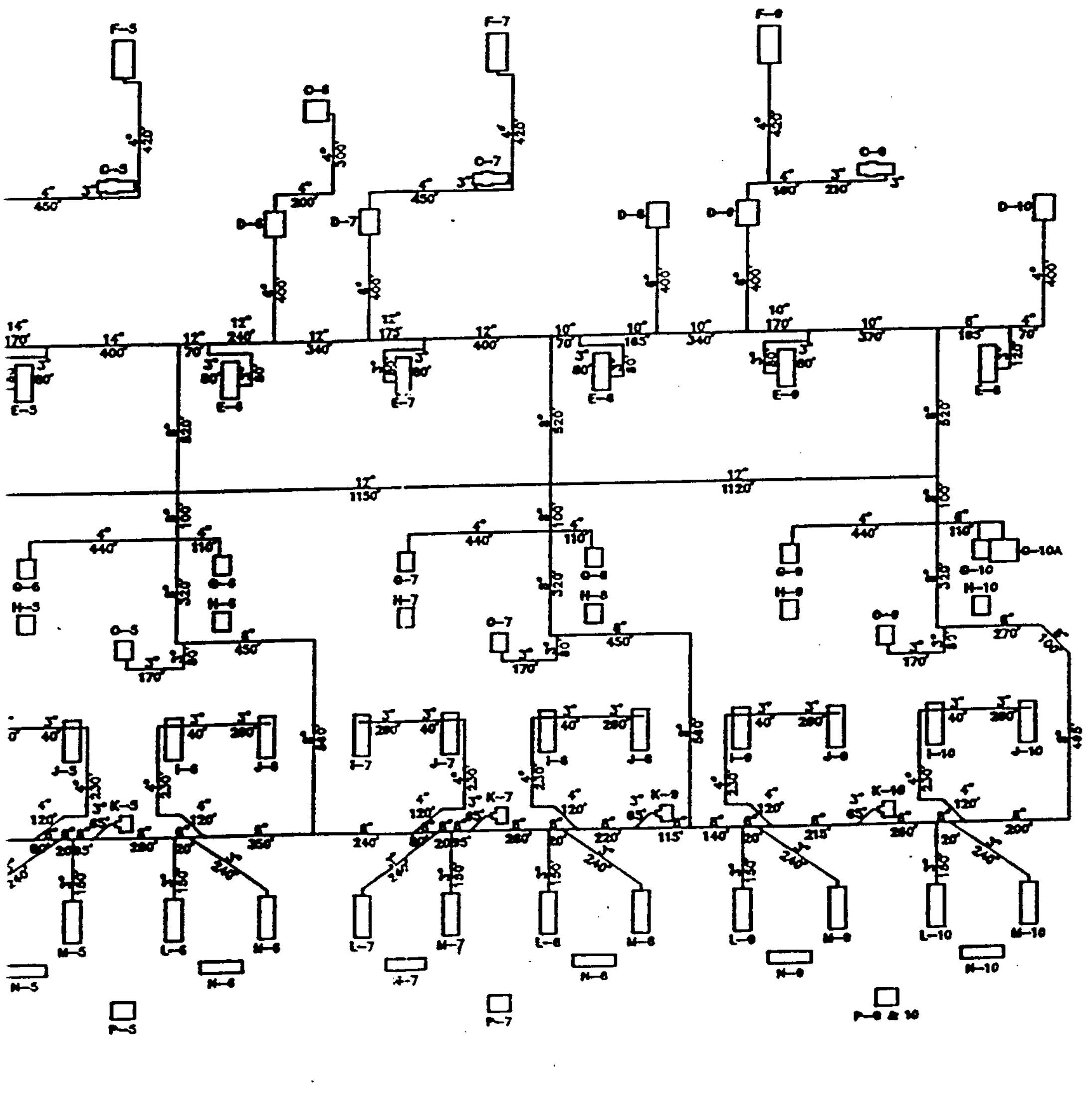

FIGURE 4-1
AREA-B STEAM DISTRIBUTION
SYSTEM SCHEMATIC

(3)

4.3 EVALUATION APPROACH

4.3.1 Existing Cogeneration System

There is an existing 400 kW steam turbine-generator in Building B-6 which is only two years old, but is inoperable. Discussions with maintenance personnel indicate that they have not had time to trouble-shoot the problem, but believe there is a control problem. Discussions with turbine manufacturers indicate that the problem is likely that the speed control needs adjusting, a procedure which should be performed annually.

Not knowing the exact problem, repair costs are difficult to quantify. Repair costs are estimated at $5,000 based on a 5 day field visit by the turbine manufacturer, including $1000 for parts.

Upon completion of repairs, the annual energy cost savings are estimated to be $41,887 with a resulting simple payback of about one month. Considering the economic benefit, the steam turbine should be repaired immediately with O&M funds.

The analysis of the proposed steam turbine-generator assumes that 300 psig steam will continue to be supplied to the existing steam turbine-generator in Building B-6.

4.3.2 Proposed Cogeneration System

Evaluation of the cogeneration ECO proceeded as follows:

1. A base case steam load was developed using historical steam production records, weather data, and steam distribution system heat loss calculations. The base case steam load is the steam load which the steam turbine-generator system must supply. The base case electrical loads and base case energy costs were also developed.

2. The steam distribution system was simulated to determine the minimum steam pressure at which the steam distribution system could operate and still meet all building steam pressure requirements. The turbine back pressure of the steam turbine-generator system is set by the minimum steam pressure of the steam distribution system. A flow and pressure drop model of the steam distribution system was developed which required the following inputs:

   - Steam distribution system geometry.
   - Steam pressure requirements for each building.
   - Peak space heating and process steam demand for each building.

   The capacities of PRVs and steam traps at the lower pressures were also investigated.

3. Two options for turbine back pressure were identified:

   - A 175 psig option which requires no modification of the existing steam distribution system.

- A 110 psig option which requires the addition of a new steam line to serve the administration area.

4. The performance of the cogeneration system was then calculated to determine the consumption of coal in the CHP, and the amount of electricity generated for the two options. A simplified economic analysis was performed for the two options. Based on the results of the analysis, the 110 psig option was selected for further detailed evaluation.

5. A conceptual design of the 110 psig option was completed in order to determine the construction of the cogeneration system.

6. Finally, system construction costs were estimated and a Life Cycle Cost Analysis performed.

4.4 BASE CASE STEAM AND ELECTRIC LOADS

4.4.1 Historical Steam Usage

Monthly metered steam usage over the last two years at Area-B is indicated in Figure 4-2 on page 4-6. Steam usage is fairly consistent from year to year, but varies monthly in response to space heating loads. Analysis of the CHP indicates that an average of 16.5% of the steam metered at the boilers is used within the CHP. The remaining steam usage may be divided up into three categories

- Steam distribution system heat loss.
- Space heating loads.
- Process loads.

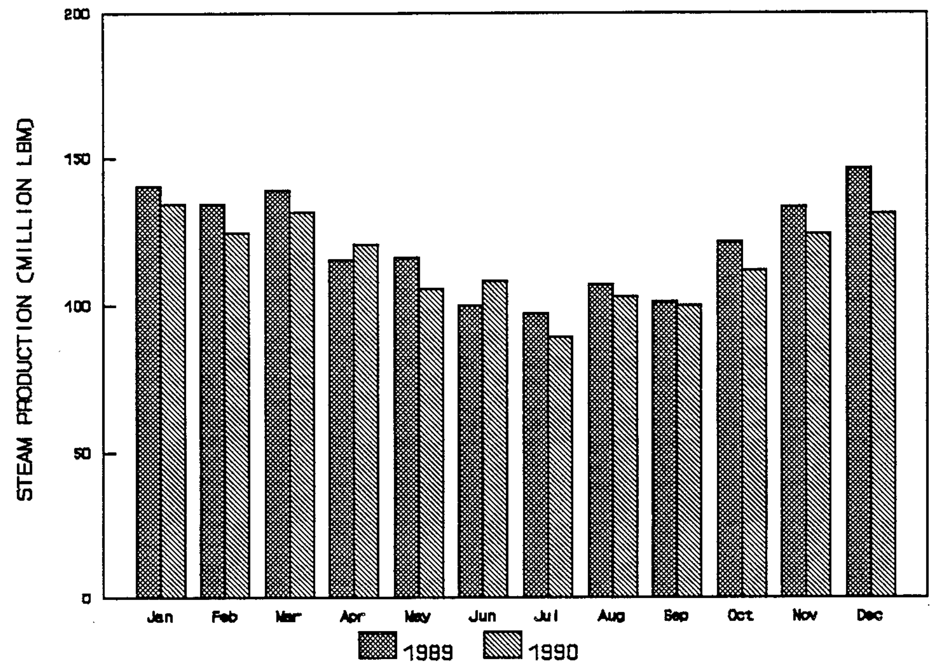

FIGURE 4-2. AREA-B HISTORICAL STEAM PRODUCTION

4.4.1.1 Steam Distribution System Heat Loss

Steam is distributed to Area-B facilities through a steam distribution system almost 40,000 feet in length. Heat losses from the steam distribution system were determined in a 1983 EEAP report prepared for the HAAP by A.M. Kinney, Inc. (referred to as the Kinney EEAP Report) at 10.6 MBtu/hr. Surface temperatures of the outer insulation casing were measured during the field survey. The casing temperature on a 24 inch pipe was measured at 105°F with the ambient air temperature at 56°F. Using the steam temperature of 525°F and the projected heat loss from the Kinney EEAP Report, an equivalent surface temperature was calculated. This analysis verified that the data in the Kinney EEAP Report was approximately correct.

The total heat loss from the steam distribution system was divided by the difference between the steam temperature and average ambient temperature to obtain a steam distribution system heat loss coefficient of 22,662 Btuh/°F.

Steam trap steam losses from the steam distribution system were assumed to be negligible. Condensate generation in the steam distribution system is minimal due to the superheated steam from the CHP.

4.4.1.2 Process Loads

Process loads were estimated to be the average of the summer steam demands of Area-B less the pipe losses. Space heating demands were assumed to be zero in the summer. Process loads are constant throughout the year and were calculated at 77,027,000 pounds of steam per month, or an average of 106,982 lbm/hr.

4.4.1.3 Space Heating Loads

Monthly space heating loads were computed by subtracting in-plant steam use, steam distribution system heat loss, and process loads from the metered steam usage. A space heat coefficient was calculated by dividing the total space heating loads over the last two years by the base 65°F heating degree days for the period. The resulting space heat coefficient is 1,865,000 Btuh/°F. The space heat load is then the space heat coefficient times the degree days for the period. Figure 4-3 below compares the space heating loads from the metered data to the space heating loads calculated by the degree day model over the first two years. As can be seen, the degree day model closely predicts space heating loads.

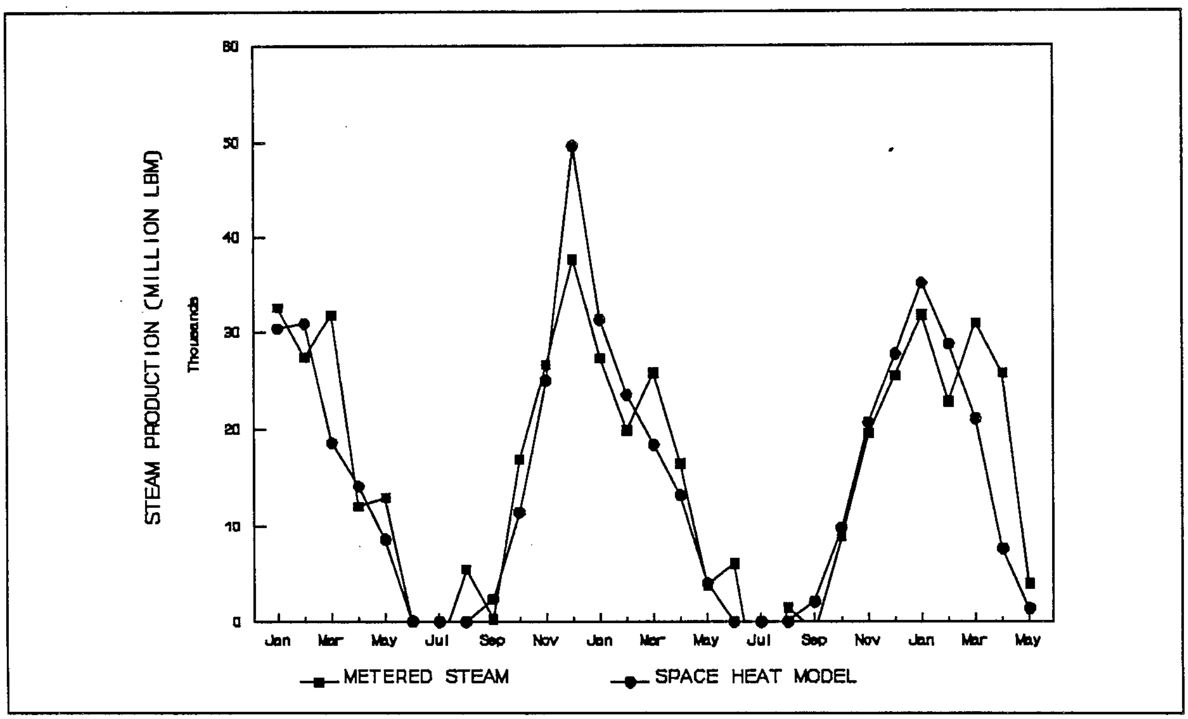

FIGURE 4-3. AREA-B SPACE HEATING LOADS

4.4.1.4 Base Case Steam Loads

With steam distribution system heat loss, process loads, and space heating loads quantified, a base case steam load on the Area-B CHP can be defined. It is essentially a monthly steam load for a statistical weather year based on constant process loads and on space and pipe steam loads which vary with ambient air temperature. A plot of the base case steam load is shown in Figure 4-4 below. The base case steam load is comprised of the following:

- Steam distribution system heat loss is the steam distribution system heat loss coefficient (22,622 Btuh/°F) times the difference between the steam distribution temperature (currently 525°F) and the average monthly ambient temperature. (Refer to §4.4.1.1)

- Process loads of 106,982 lbm/hr of 300 psig/525°F steam. (Refer to §4.4.1.2)

- Space heating load is the space heat coefficient (1,865,000 Btuh/°F) times the degree days in the month. (Refer to §4.4.1.3)

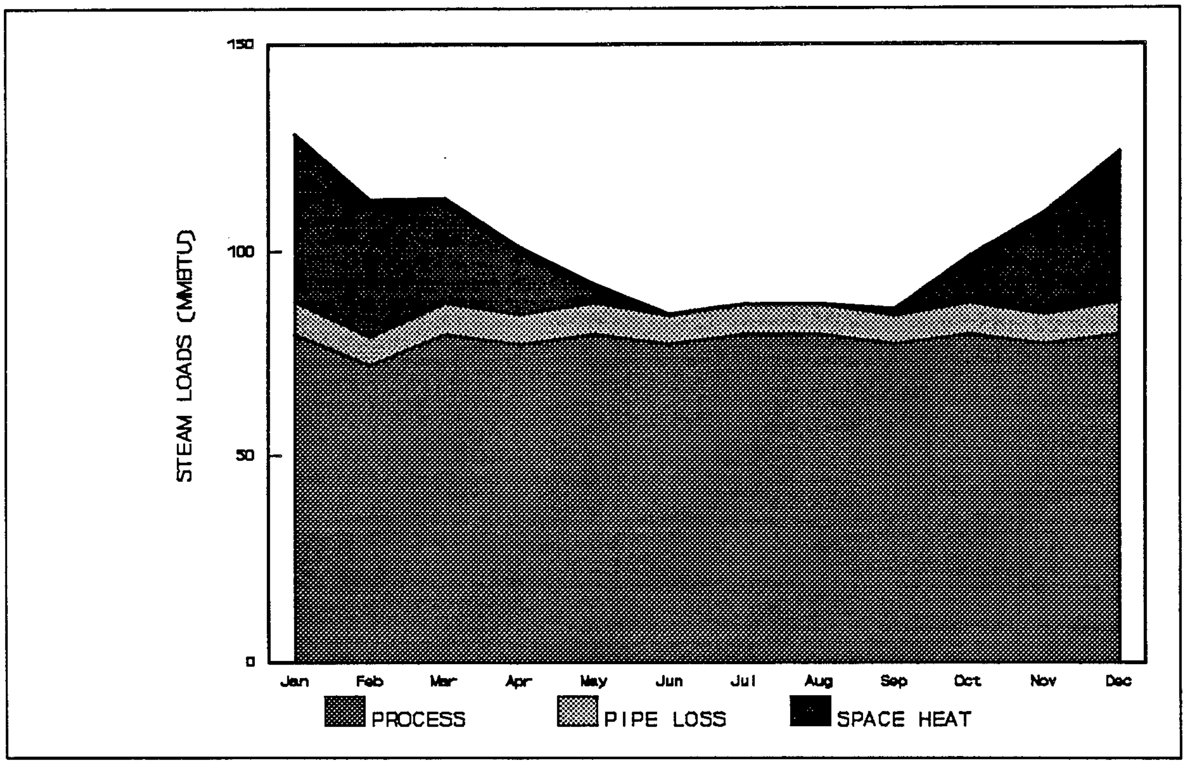

FIGURE 4-4. AREA-B BASE CASE STEAM LOAD

Figure 4-4 above illustrates the base case model. The steam distribution system heat losses and process loads stay fairly constant throughout the year, while the space heating load is zero in summer and peaks in January.

4.4.2 Base Case Electrical Loads

Typical hourly electric demands are shown in Figure 4-5 below. The graph shows that the demand varies by day of the week. Discussions with HAAP personnel indicate that demand variation is the result of operating schedules of various electrical equipment, mostly large motors. It was also indicated that all weeks throughout the year follow the same electrical profile. The steam turbine-generator would generate approximately 800 kW of electrical power, which would be relatively constant throughout the year. The 800 kW generated is far below the minimum electric demand of 5,000 kW, so no power would be sold to the utility company.

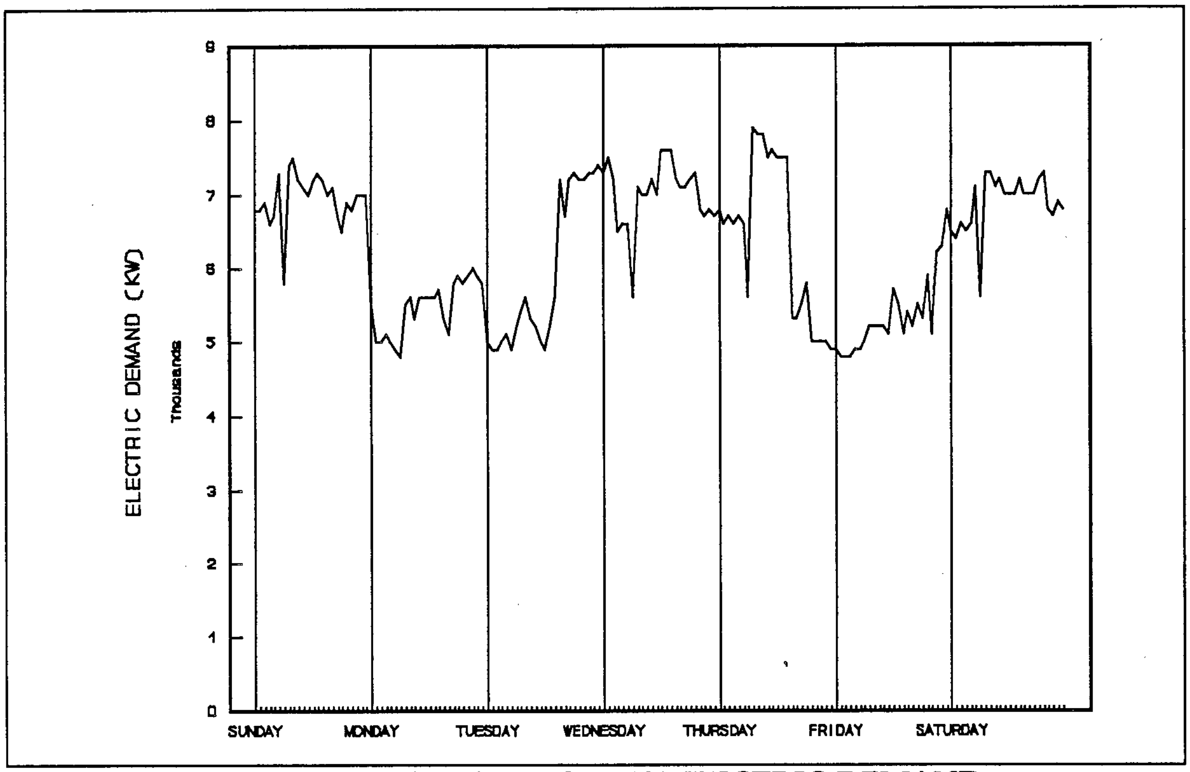

FIGURE 4-5. AREA-B HOURLY ELECTRIC DEMAND

4.4.3 Base Case Energy Costs

Using the incremental energy costs developed in Section 2.0 and the base case energy usage developed above, the base case energy costs were determined and are summarized in Table 4-1 below.

TABLE 4-1
AREA-B BASE CASE COGENERATION ENERGY COSTS

Energy Source	Unit Energy Cost	Base Case Energy Usage	Energy Cost
Coal	$1.25/MBtu	2,086,488 MBtu	$2,608,110
Electricity	$0.01585/kWh $9.50/kW	58,753,486 kWh 8,268 kW	$936,456 $942,552
Total			$4,487,118

These are the costs against which the cogeneration ECO was evaluated.

4.5 STEAM DISTRIBUTION SYSTEM SIMULATION

The minimum steam turbine back pressure was determined by simulating the steam distribution system as follows:

- Define the steam distribution system geometry and construct a complete model.
- Determine the minimum steam pressure requirements for each building.
- Determine the peak space heating and process loads.

The existing steam distribution system is supplied steam at a pressure of 300 psig. In a cogeneration system, this high pressure would be used to drive a steam turbine-generator set. The steam would exit the turbine at the turbine back pressure. The lower pressure steam would be delivered through the steam distribution system to space heating and process loads.

The amount of steam which can be supplied through a steam distribution system is proportional to the density of the steam, which is proportional to the steam pressure. For instance, a steam distribution system operating at 300 psig will supply 2.5 times the steam of a system operating at 100 psig. Determination of the minimum steam distribution system pressure requires knowing the peak steam demand, the distribution of peak steam demand, and the ability of the steam distribution system to deliver steam to each building at the required pressure.

4.5.1 Steam Distribution System Geometry

The "Pipe Network Simulation Analysis Computer Program" (NETWK) was used to simulate the steam distribution system. The program calculates steam flow rate and pressure for designated system components. The program uses the mass and energy conservation laws, and assumes the sum of pressure drops around a loop is equal to zero. The program performs a matrix solution of the system equations using the Newton-Raphson iteration technique to ensure quick convergence.

Nodes are assigned to critical points throughout the system. These critical points include tees, changes in pipe diameter, and points where steam is removed from the system for space heating or process loads. Each branch of pipe is also given a number. The lengths and diameters of the pipes are also input into the program.

A flow model was developed for Area-B using the NETWK program. The existing steam distribution system was modeled as a series of nodes and branches which identified the geometry of the system. The central heating plant was modeled as a 300 psig reservoir. Space heating and process steam demands were assigned to appropriate nodes. The steam turbine-generator for this ECO was located at node 1 near the CHP.

4.5.2 Steam Pressure Requirements

For space heating and most process use within Area-B, steam pressure is reduced to 30 psig by pressure reducing valves (PRV) upstream of the application. Requirements for higher pressure steam include:

- Building B-6 has a 400 kW steam turbine-generator requiring 300 psig steam. Low pressure steam from the turbine exhaust provides energy for the remaining B-line buildings. This steam turbine-generator is currently inoperable and a PRV provides steam for the remaining B-line buildings.

- The acid area has a cracking column in Building-334 which requires 300 psig steam.

- Steam jet vacuum systems in process buildings throughout Area-B require 100 psig steam.

- Steam engine stirrers in the M buildings are operated on 300 psig steam. It has been determined that 100 psig steam can likely be used to operate these engines. These engines should be tested to verify operation at 100 psig prior to construction of a cogeneration system.

- The administration area is served by a PRV station which reduces steam pressure to 100 psig. Secondary PRVs at each building in the administration area reduce steam pressure to 30 psig.

Based on the above requirements, a pressure of 100 psig was determined to be the minimum pressure supplied to most production buildings. Buildings 334 and B-6 require 300 psig steam. For this ECO, the steam distribution system would be divided into two steam

distribution systems, one operating at 300 psig and the other at the new turbine-generator back pressure. The existing steam distribution system would be configured using existing valves to segregate 300 psig and 100 psig distribution. Figure 4-1 on page 4-3 indicates the portion of the steam distribution system to be operated at 300 psig.

4.5.3 Peak Space Heating Load

Historical space heating energy usage resulted in a space heating coefficient of 1,865,000 Btuh/°F for all of Area-B. At an outdoor design temperature of 9°F, the peak heating load is 104.4 MBH. A total of 101,600 lbm/hr of 300 psig steam is required to meet the 104.4 MBH peak heating load.

The Kinney EEAP Report indicated a peak heating load of 30.0 MBH. The heating load, based on historical data, is 3.5 times that predicted by the Kinney EEAP Report. The Kinney Report did not include ventilation or infiltration loads and may have missed buildings which are still being heated. The approach taken by this study was to use the Kinney EEAP Report data to apportion the historical peak heating demand to individual buildings. This was accomplished by multiplying the EEAP peak heating load by the 3.5 correction factor.

4.5.4 Peak Process Load

The process steam usage and loads were not included in the Kinney EEAP Report. A previous study entitled, "Methods for Conservation of Energy at Holston Army Ammunition Plant" (DACA09-78-C-3000) by Dupont, presents theoretical figures on process energy requirements (by chemical analysis). The report includes information on many of the buildings, or at least on building types throughout the system. It was assumed that if the process is the same for two buildings, then the process load is also the same. Theoretical process loads were found for each type of process building. Theoretical process loads were calculated at 85,849 lbm/hr based on this theoretical data.

The historical process load is 106,982 lbm/hr based on historical data (see §4.4.1.2 for details). Dividing the historical process load by the theoretical process load gives a ratio of 1.25. The difference is likely due to heat loss from the uninsulated jacketed tanks, leaking steam traps, and other heat loss within the process building. The historical process load was used to correct the theoretical process loads by multiplying the theoretical process load from each building by the 1.25 ratio.

There is some diversity in process load. Figure 4-6 on the following page indicates hourly steam production during a period of minimal space heating load. The hourly peak steam load varies by up to ±10% of the average steam load. To ensure sufficient steam through the system, the process load for each building was multiplied by 1.2. Table 4-2 on page 4-13 summarizes the process loads. The resulting peak process steam demand is 128,380 lbm/hr.

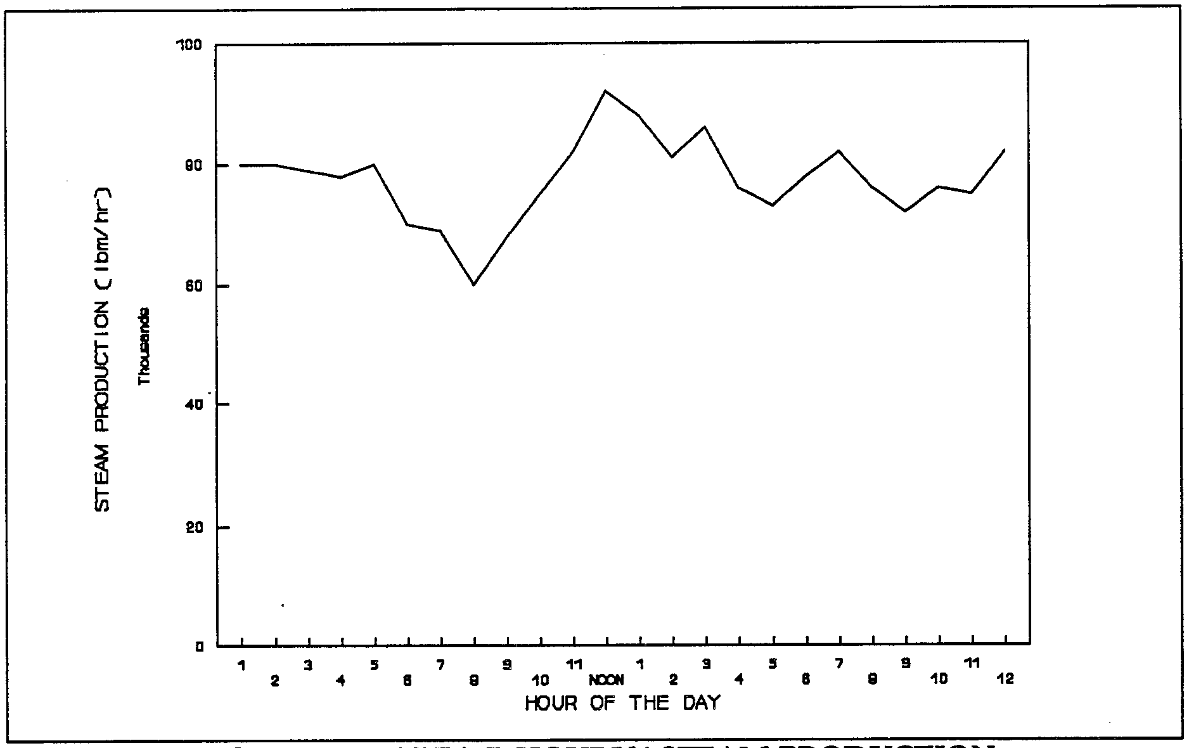

FIGURE 4-6. AREA-B HOURLY STEAM PRODUCTION

TABLE 4-2
AREA-B PROCESS STEAM LOADS

Building	No. of Buildings	Theoretical Steam Load (lbm/hr)	Peak Steam Load (lbm/hr)
302	1	17,775	26,663
334	1	19,970	29,955
B-6	1	18,000	27,000
D's	2	1,223	1,835
E's	3	544	816
G's	5	5,205	7,808

4.5.5 Simulation Results

Simulation of the steam distribution system resulted in two options for turbine back pressure:

- The 175 psig Option. The lowest turbine back pressure was determined to be 175 psig for the existing system. This pressure is necessary to distribute steam to satisfy demands and pressure requirements throughout the system. The limiting factor is the steam line serving the shop and administration areas. A six inch pipe serves the shop area with a four inch extension serving the administration area. With 175 psig steam exiting from the cogeneration steam turbine, steam pressure would be maintained at a minimum of 165 psig throughout the process area, but would drop to 30 psig by the time it reached the administration area.

- The 110 psig Option. The existing steam distribution system would be modified by running a new six inch steam line from the production area to the administration area, as indicated in Figure 4-1 on page 4-3. With this new line, a steam turbine back pressure of 110 psig would be required to supply a minimum of 100 psig to the process area and to provide 30 psig to the administration area.

4.5.6 PRVs

The steam distribution system serves PRVs at each building or process. At lower steam main pressures the PRVs have less capacity.

Nameplate data on the PRV's at active production buildings were taken during the field study. Analysis and manufacturer's data indicate that a reduction of steam main pressure from 300 psig to 110 psig will result in a capacity reduction to about 45% of that at 300 psig.

The average process loads for each building were compared to the capacity of the valve operating at 110 psig. In all cases for which data was available, the capacity of the PRV at 110 psig is at least five times the average load. Most of the process steam is used for adding heat to processes which are fairly steady loads. Peak steam loads are not likely to exceed five times the average load.

The process steam jet vacuum systems would likely have higher peak to average ratios at 110 psig due to more intermittent operation. The steam jets require 100 psig steam and PRV capacity is affected more significantly than the process heating loads (30 psig). Existing 100 psig systems could be converted to 110 psig by bypassing existing PRVs.

4.5.7 Steam Traps

The purpose of the steam traps is to take condensate, air, and carbon dioxide out of the steam equipment and piping as fast as they accumulate. Most of the steam traps are downstream of the PRVs on equipment and would not be affected by the change in steam main pressure. There are a few steam traps on the steam distribution system which would be affected. When the pressure is lowered, the steam traps suffer a 45% capacity reduction similar to the PRV's.

Because of the superheat in the steam from the CHP, little condensate is generated in the steam distribution system. Condensate generation in the steam piping is minimal at about 1500 lbm/hr for the entire system. Under these superheat conditions the existing steam traps are adequate.

A cogeneration turbine operating with a back pressure of 110 psig would provide steam superheated to about 400°F. Under this condition condensate generation would be less than at 300 psig. Therefore, existing steam traps are adequate.

4.6 COGENERATION SYSTEM PERFORMANCE

This section details the calculation of energy savings and a simplified economic analysis of the two steam turbine back pressure options. The purpose is to select the optimal option for conceptual design and life cycle cost analysis.

4.6.1 Steam Flow

Based on the preceding analysis, steam flow available for the steam turbine-generator for this ECO includes all of the steam load at Area-B with the exception of the following two buildings:

- Building B-6 has a 400 kW steam turbine-generator requiring 300 psig steam. The average process steam load is estimated at 22,500 lbm/hr.
- Building-334 a has a cracking column which requires 300 psig steam. The average process steam load is estimated at 24,962 lbm/hr.

Unfortunately, these two buildings account for approximately 47,462 lbm/hr or 44% of the average process steam load. The resulting average steam load available for cogeneration is approximately 92,142 lbm/hr for the year with monthly averages ranging from 70,000 lbm/hr to 125,000 lbm/hr. (See Appendix C-5 for a monthly tabulation.)

4.6.2 Electric Generator

There are two types of electric generators available, synchronous and induction. The basic difference between the two is in the exciter. The synchronous generator has an exciter which produces the magnetizing field in the generator. The induction generator does not have an exciter, but draws its excitation from the bus. The synchronous generator was chosen over an induction generator because:

- The synchronous generator can operate by itself. If commercial power is lost the induction generator cannot operate, but the synchronous will continue to generate power without interruption.
- The synchronous generator can improve the plant power factor by operating in a manner which allows it to carry a reactive load. This improves the power factor. The

induction generator tends to lower the overall power factor, because it takes its excitation from the power line.

Electric generators in the desired size range can be purchased with generating voltages up to 13,800 volts. There is a 13,800 to 480 volt transformer adjacent to the proposed cogeneration site which provides two options for generator voltage:

- Generation at 13,800 volts allows direct tie in to the 13,800 volt plant distribution grid.
- Generation at 480 volts requires power to be back-fed through the transformer to the plant distribution grid.

Vendor quotes indicate an additional cost of about $50,000 for a 13,800 volt generator over that of a 480 volt generator. For the desired size range, a 13,800 volt generator must be custom built. Considering the additional cost of the 13,800 volt generator, the 480 volt generator was selected.

4.6.3 Cogeneration Model

In optimizing the cogeneration system the goal was to size the system with the lowest simple payback. A cogeneration model was developed which calculated annual energy savings, capital costs, and simple payback for the two cogeneration system alternatives identified. Essential elements of the cogeneration model include the following.

- Monthly space heating steam loads were calculated based on degree days and the space heating coefficient developed from historical steam usage data.
- Average process steam loads were calculated based on historical steam usage data. Process demands which must operate at 300 psig were calculated in §4.6.1.
- Steam distribution system heat loss was calculated based on steam temperature, average ambient temperature, and the pipe loss coefficient developed from the Kinney EEAP Report. Pipe heat loss does not remove steam from the system, but does remove energy which is accounted for as a steam load.
- Monthly average steam load available for cogeneration is the total steam load less that required for 300 psig processes. Steam used for cogeneration is limited by either the turbine size or the steam load.
- Electricity generated was calculated based on the steam rates provided by steam turbine-generator suppliers. Part load performance was calculated based on the standard turbine characteristic of 60% steam at 50% load. Full time operation was assumed. At optimal sizing, cogenerated electricity is less than 10% of the historical electric demand.
- Steam load on the CHP is the sum of the cogeneration steam, the desuperheater steam, and the 300 psig process steam.

- Boiler steam load is the sum of the CHP external load and the CHP in-plant steam use. Monthly coal usage was calculated based on the boiler efficiency and the boiler steam load.

- Monthly coal, electric usage, and electric demand costs were then calculated and totaled for the year. Annual energy cost savings are the calculated energy costs less the annual cost with no cogeneration.

- Estimated investment costs for the different sized cogeneration systems were based on steam turbine-generator package price quotes from vendors plus estimated costs for additional equipment, piping, electrical switchgear, and a small utility building. An 0.7 exponential scaling factor was used to modify costs for different sized systems. Past experience has shown that an 0.7 economy of scale factor is appropriate for cogeneration systems. Costs for steam distribution system modifications for the administration area were calculated separately. Estimated cost for running a six inch steam main to the administration area was $134,000.

- Simple payback in years is the investment cost divided by the annual energy cost savings.

4.6.4 Results of Analysis

Figure 4-7 on the following page shows the simple payback calculated by the cogeneration model for the two turbine back pressure options. This figure indicates that the 110 psig option has the best payback and that the optimal turbine should be sized near 60,000 lbm/hr.

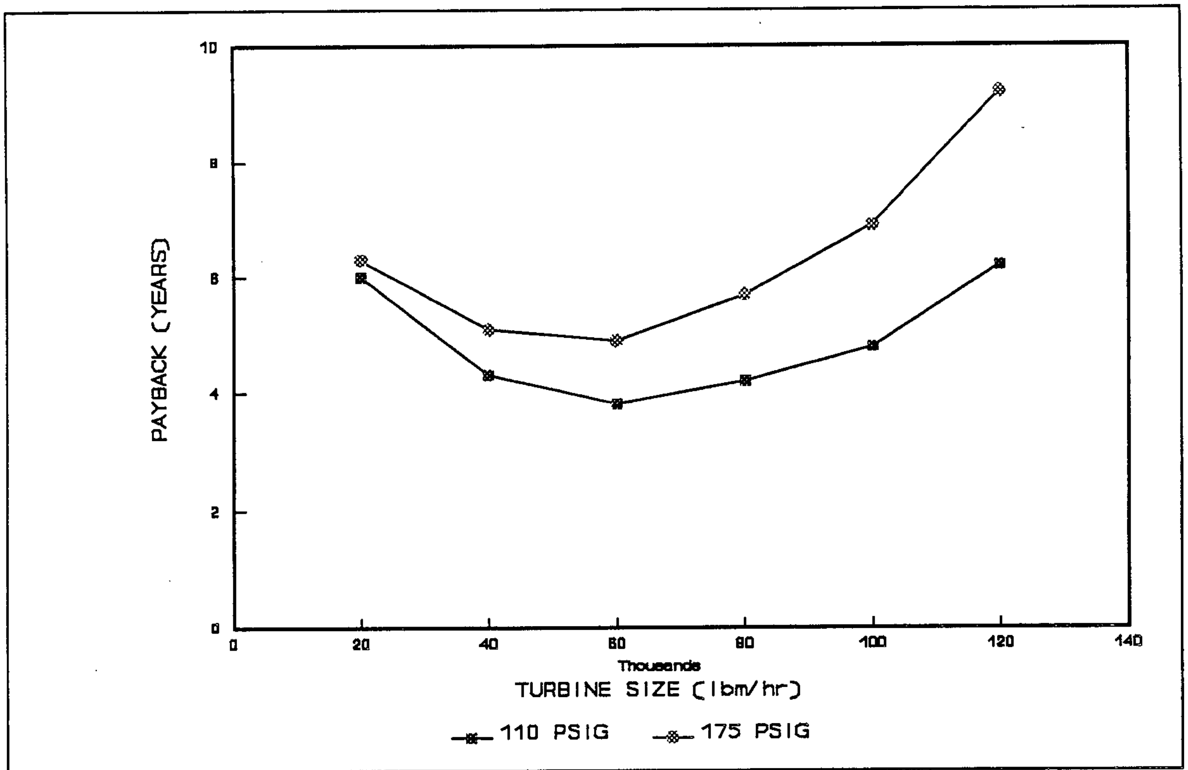

FIGURE 4-7. COGENERATION SYSTEM OPTIMIZATION

Based on the above anlaysis, a steam turbine-generator operating with a back pressure of 110 psig was selected for the conceptual design and Life Cycle Cost analysis.

4.7 CONCEPTUAL DESIGN

4.7.1 Steam Turbine-Generator Layout

The site proposed for the steam turbine-generator is the area between transformer stations on the North side of the Area-B CHP, and between the railroad tracks and the existing 14-inch steam line (see Figure 4-8 on the following page). This location is near the 16-inch steam line that is to be the tie-in point for the 300 psig steam and the delivery point for the 110 psig steam. The steam turbine-generator can be bypassed during mobilization by operating three valves.

The steam turbine-generator would be installed on a concrete housekeeping pad on the concrete slab of a 30-foot by 12-foot pre-engineered steel building. The building would also house the piping, valving, steam traps, pressure-reducing station, de-superheater, and the electrical switchgear.

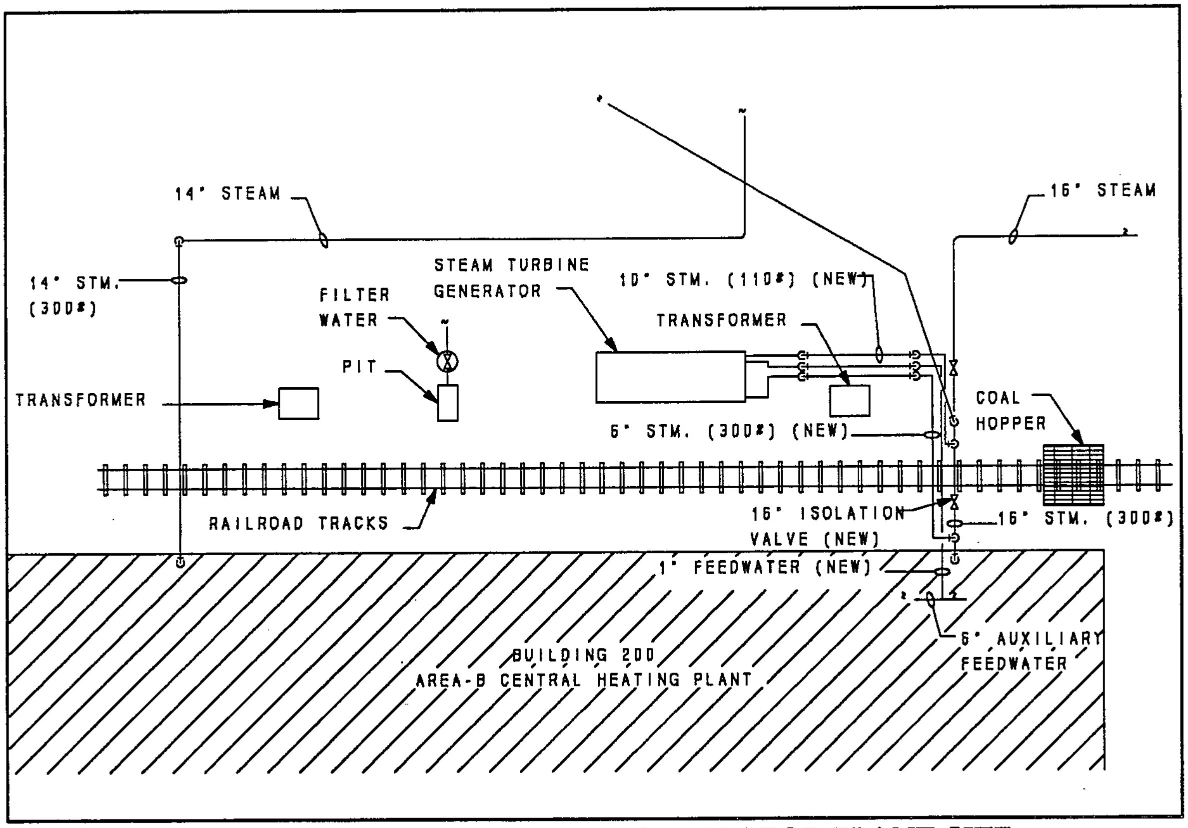

FIGURE 4-8. STEAM TURBINE-GENERATOR PLANT SITE

4.7.2 Steam Turbine-Generator Plant Schematic

Peak steam load from process and space heating loads (see §4.6.1), less 300 psig process steam demand, is approximately 125,000 lbm/hr. Approximately 65,000 lbm/hr of steam would be used for cogeneration. The balance of the steam required must bypass the steam turbine and be reduced in pressure and temperature by a pressure-reducing station and de-superheater. The desuperheater reduces steam distribution system temperature and heat loss, thus conserving energy.

Figure 4-9 on page 4-19 is a one-line steam piping schematic of the steam turbine-generator plant.

Because the heating demand varies from its maximum in the winter to zero in the summer, the bypass pressure reducing (PRV) station must be sized for the variation; 70,000 lbm/hr to 125,000 lbm/hr. A dual-valve PRV station is proposed. The amount of condensate formed in the steam-turbine-generator plant is expected to be small because of superheat remaining in the steam. Therefore, the condensate will be expelled to the drain and not returned to the CHP.

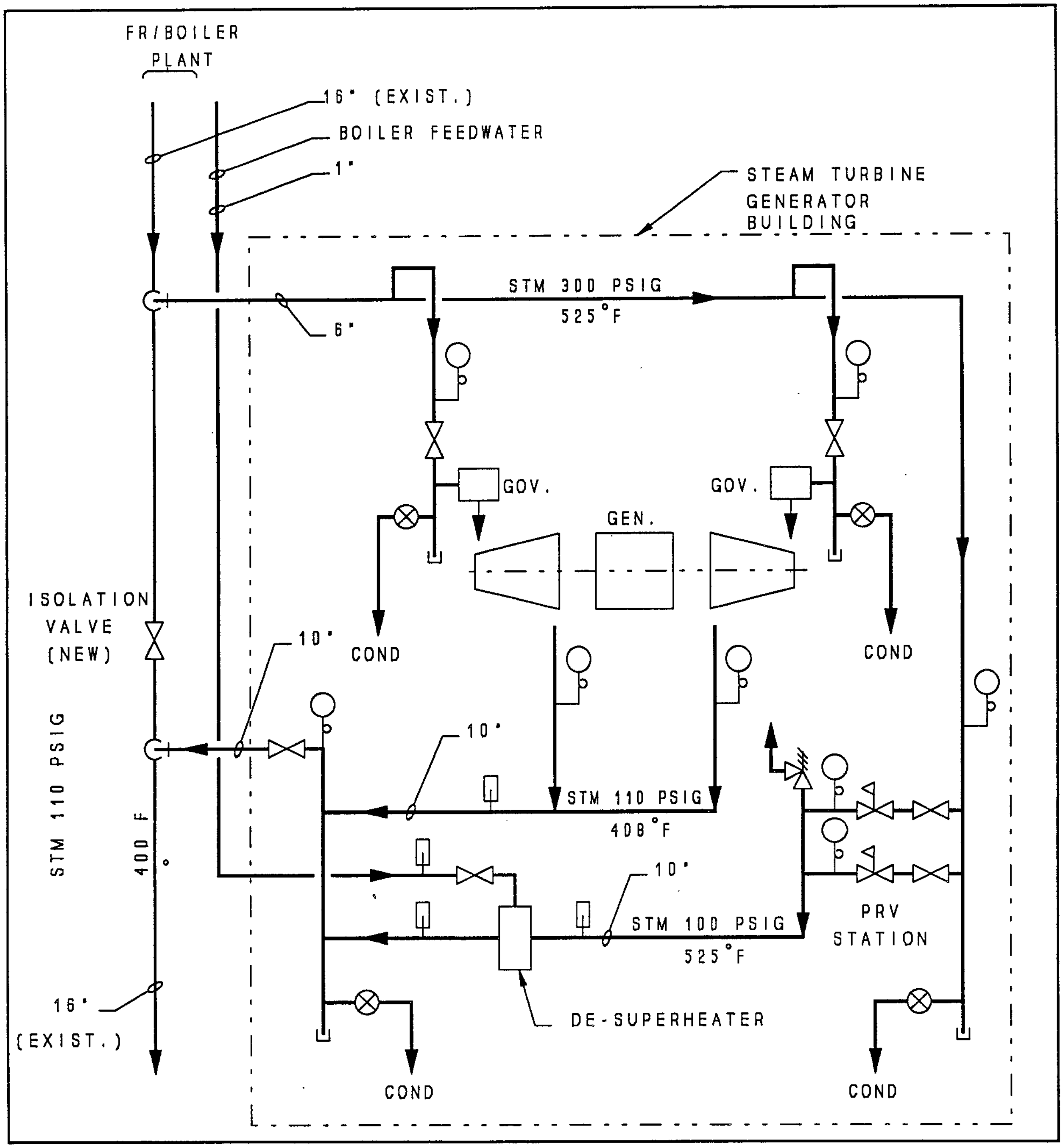

FIGURE 4-9. SYSTEM PIPING SCHEMATIC

The steam turbine-generator would be a back-pressure type taking steam at 300 psig and exhausting it at 110 psig. The steam temperature is reduced from 525°F to 408°F due to expansion of the steam through the turbine. The exhaust steam is still superheated approximately 80°F above saturation temperature. This is desirable because it limits the amount of condensate formed during transmission and assures proper pressure at the point of use.

4.7.3 Core Equipment Selection

Quotes for steam turbine-generator sets were requested from five manufacturers. Pre-assembled systems including turbine, auxiliary systems, generator, controls, and electrical switchgear were specified. Installation essentially consists of running steam pipes and electrical conductors to the unit. Quotes were requested for turbines operating with back pressures of 110 psig and 175 psig with generator options at 480 and 13,800 volts.

Core equipment for life cycle cost analysis was selected on the basis of simple payback analysis of manufacturer's estimates plus additional costs. Total cogeneration system costs included the following elements:

- Steam turbine-generator set costs including freight, installation, and start up.
- Support system costs including steam piping and accessories, and a structure in which to house the system.
- Electrical costs including feeders and additional switchgear, and electrical service to the new structure.
- Costs for additional steam pipes to the administration area.

Annual energy cost savings were calculated for each vendor steam turbine-generator estimate using the cogeneration model. A summary of the economics of each alternative are presented in Table 4-3 on the following page.

The total investment cost was divided by the annual energy cost savings to calculate simple payback. Maintenance costs were not included, but electric demand savings were included. Based on the least simple payback of 3.9 years, the Coppus-Ewing steam turbine-generator operating with a 110 psig back pressure was selected for life cycle cost analysis.

TABLE 4-3
STEAM TURBINE-GENERATOR ESTIMATES

MANUFACTURER	POWER OUTPUT (KW)	STEAM FLOW (lbm/hr)	STEAM PIPING PRESS (PSIG)	TOTAL INVESTMENT COST ($)	ANNUAL COST SAVINGS ($)	SIMPLE PAYBACK (YRS)
COPPUS-EWING	813	67,700	110	$524,505	$134,488	3.9
DRESSER-RAND	750	65,000	110	$499,925	$128,186	3.9
DRESSER-RAND	1,150	80,000	110	$838,925	$164,495	5.1
COPPUS-EWING	813	67,700	110	$616,265	$136,948	4.5
DRESSER-RAND	750	65,000	110	$577,925	$128,428	4.5
DRESSER-RAND	420	65,000	175	$349,200	$68,471	5.1
DRESSER-RAND	400	65,000	175	$366,200	$65,393	5.6
DRESSER-RAND	420	65,000	175	$419,200	$68,721	6.1
DRESSER-RAND	400	65,000	175	$444,200	$65,324	6.8

4.7.4 Interface with Existing Equipment

4.7.4.1 Mechanical Interfaces

Major mechanical interfaces required are the tie-ins to the 16-inch steam main after it exits the CHP near the east end, and the tie-in to the auxiliary feedwater line inside the Area-B CHP near the front end of Boiler No. 1.

Tie-ins would require shutting down necessary lines and would require coordination with plant operating schedules.

There appears to be a flanged connection in the 16 inch main approximately where the line passes over the railroad tracks. This is probably the best location for the new valve isolating the 300 psig portion of the main from the 110 psig portion. The tie-in for the 6-inch supply line to the Cogeneration Plant should be made between the new isolation valve and the wall of the Area-B CHP. The 10-inch output line from the Cogeneration Plant would be tied into the 16-inch main downstream, between the new isolation valve and the existing branch line.

The 1-inch tie-in to the 6-inch auxiliary boiler feedwater line would be made in approximate alignment with where the 16-inch main exits the Area-B CHP wall, so that the 1-inch line projected to be required could be run parallel to and supported with the 16-inch main to a point near the 10-inch tie-in to the main and from there to the steam turbine-generator plant building, and its connection point to the de-superheater.

4.7.4.2 Electrical Interfaces

Electrical switchgear provided by the steam turbine-generator set manufacturer should be specified with controls for voltage regulation, reactive power output and automatic synchronization. The equipment should also include complete generator and bus metering and all protective relays necessary for connection to the utility.

Kingsport Power has established requirements for interconnection of cogeneration facilities to systems which they serve. These safeguard personnel and equipment and insure reliable operation of the cogenerator with the utility system. It is anticipated the controls and protection installed with this system would fully satisfy the interconnection requirements of the utility company.

The electrical distribution system connection for the cogeneration facility would be made at the low voltage side of CHP Substation No. 1, which is a 1500 kVA pad mounted transformer. Figure 4-10 on page 4-24 is a one line diagram of the proposed tie-in. This tie-in would require installation of a new 2000A main bus switchboard at the transformer secondary. The switchboard would have two 1200A switches; One would be connected to existing cables which feed the steam plant switchgear. The second switch would connect to a new feeder from the Cogeneration facility. This feeder would have two parallel sets of three 750 MCM cables each, sized to carry the full capacity of the 800 kW generator (962A at 480V). A bus duct may be more cost effective than the large conductors. Installation of this switch would meet requirements for a lockable disconnect at the tie-in point which is accessible to utility company personnel. Making the connection to the 480V system at this location would enable the cogeneration facility to share steam plant electrical loads with the 1500 kVA substation. If the electrical load at the substation drops below the full capacity of the 800 kW generator, then surplus power can be fed back into the 13.8 kV distribution system through the 1500 kVA transformer.

Electrical loads in the new steam turbine-generator building would be served by a 208/120 lighting panel fed by a 7.5 kVA 3-phase transformer tapped off the 480V generator switchgear (see Figure 4-10 on page 4-24). Projected loads in the facility include lighting and receptacles, ventilation, sump pump and turbine-generator support systems.

4.7.5 Power Factor Correction

The power factor of the plant distribution system is now approximately 0.94, which is much higher than the minimum value of 0.80 required by the utility company in order to avoid penalties assessed for low power factor. The 800 kW synchronous generator has the capability of supplying leading kVARs to the system should that be necessary. However, there would be no cost benefits resulting from elimination of penalties assessed by the utility company. Improvement in plant power factor would yield some decrease in I^2R losses in the plant distribution system resulting from reduction in reactive power carried by the system.

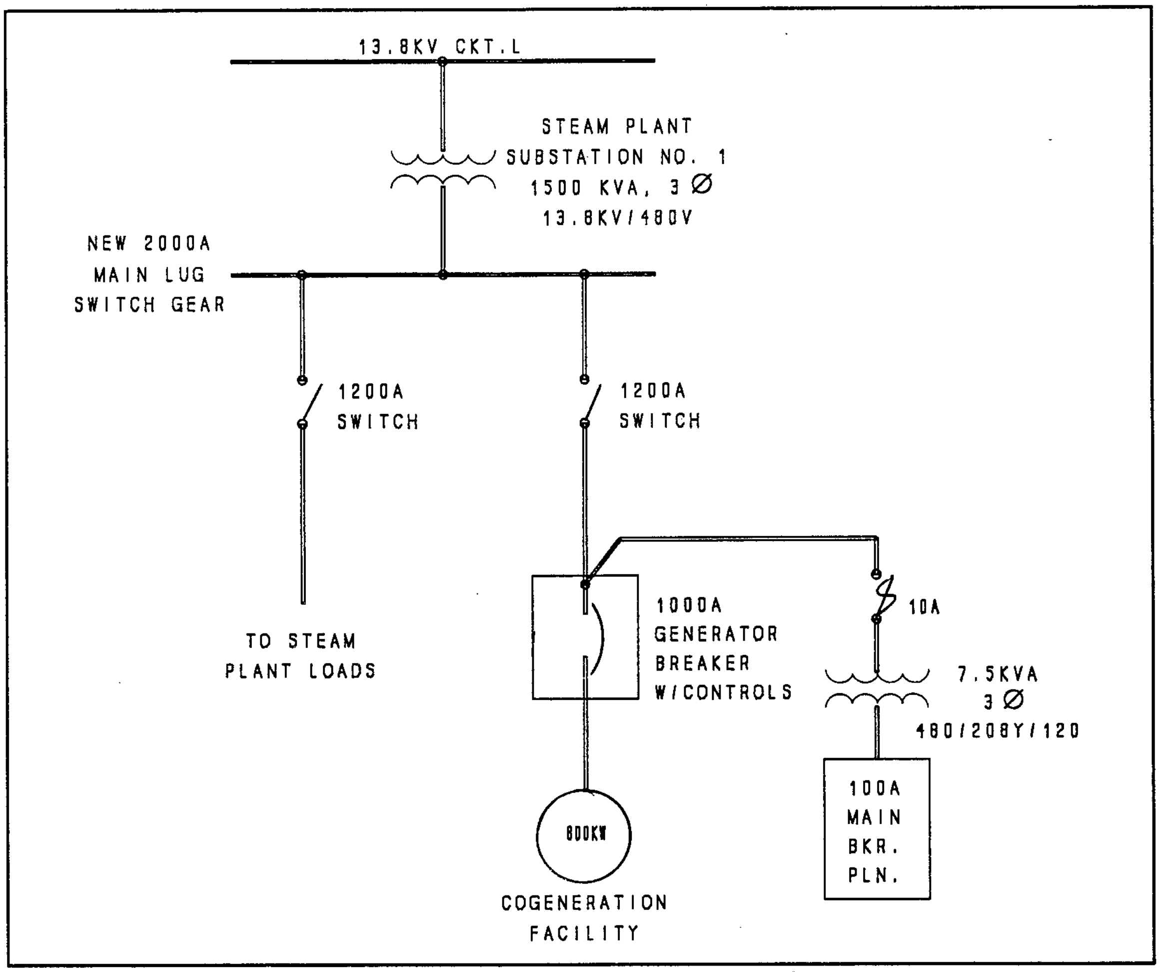

FIGURE 4-10. ELECTRICAL DISTRIBUTION SYSTEM TIE-IN

4.8 LIFE CYCLE COST ANALYSIS

4.8.1 Construction Cost

Construction costs were estimated as follows:

- Cost of the steam turbine-generator set was from vendor quotes for a package complete with controls and most of the electrical switchgear.
- Cost of the steam turbine-generator support equipment, piping, and a pre-engineered building was estimated based on the conceptual design.
- Costs for additional distribution steam piping to the administration area was estimated.
- The cost of additional necessary electrical switchgear was also estimated.

The LCCID program adds design and SIOH (Supervision, Inspection, and Overhead incurred by the Government) costs to the construction cost to obtain the investment cost.

4.8.2 Energy Savings

Energy savings were calculated using data from the cogeneration model. Annual coal savings was calculated using the cogeneration model to first obtain energy usage at current average operating conditions. The cogeneration model was then changed to simulate operation with the proposed cogeneration system and calculated the new energy usage. The difference is energy saved. The resulting electric energy savings is 9,749,780 kWh. Coal usage is calculated to increase by 14,045 MBtu. The total annual energy cost savings is $137,843. The existing cogeneration system in Building B-6 was assumed to be base loaded at 300 kW.

4.8.3 Operating and Maintenance Costs

The cogeneration system is fully automated with electronic controls and should impose little additional maintenance costs on the facility. The following maintenance costs are anticipated:

- Routine maintenance labor for the steam turbine-generator is estimated at 8 hour per month for an annual cost of $2,400.

- The turbine manufacturer should inspect and tune the turbines annually. Cost of this service is $500 per day plus expenses. Assuming four days including travel time plus $2000 in expenses, the annual cost is $4,000.

The total maintenance costs are then $6,400 annually.

4.8.4 Electric Demand Savings

Since Area-B will consume all electricity the steam turbine-generator is capable of producing, electric demand savings is equal to the average power output of the steam turbine-generator. Based on a 813 kW system, the annual electric demand savings is $92,682.

4.8.5 Life Cycle Cost Analysis Results

The annual energy savings and estimated construction costs were entered into the LCCID program with the following results.

TABLE 4-4
RESULTS

Annual Electricity Savings (MBtu)	24,307
Annual Coal Savings (MBtu)	-14,045
Total Annual Energy Cost Savings	$95,957
Annual Maintenance Costs	$6,400
Electric Demand Cost Savings	$92,682
Investment Cost	$829,000
SIR	2.4
Simple Payback	4.6

4.9 RECOMMENDATIONS

The new steam turbine-generator is recommended as an ECIP project.

Repair of the existing turbine-generator in Building B-6 is recommended as an O&M project.

SECTION 5.0

ENERGY CONSERVATION OPPORTUNITIES

This section presents the analysis for the following energy conservation opportunities.

- Area-B Vacuum Pump
- Area-B Intermediate Pressure Steam Header
- Area-B Combustion Air Preheaters
- Area-B Blowdown Heat Exchanger
- Area-B Condensate Collection
- Area-A Vacuum Pump
- Area-A Electric DA Pump
- Area-A Air Preheater
- Area-A and Area-B Inlet Air Dampers

5.1 AREA-B VACUUM PUMP

5.1.1 Description

This ECO consists of replacing the steam jet vacuum system on the Area-B ash handling system with a vacuum pump system.

5.1.2 Existing Condition

The existing vacuum system consists of an orifice plate steam jet with six, 5/16 in. holes. The steam is supplied to the orifice plate by a 2 in. steam line at 300 psi. The system is currently operated four hours per day with the steam on 75% of the time. The average hourly steam usage is approximately 7,500 lbm/hr, which yields a daily average of 22,500 lbm/day.

5.1.3 ECO Modification

Analysis indicated that a vacuum blower system is more cost effective than a liquid ring vacuum pump system. Under this ECO, the existing steam jet vacuum system would be replaced with a 50 hp vacuum blower system. Once the existing system is removed, the vacuum blower system would be installed in the same area where the steam jet vacuum system and air washer are presently located. Ash transport piping would be adapted to the vacuum blower system, and electrical service brought to the motor. A line filter should be placed upstream of the vacuum blower to protect it from any leakage and/or rupture of the bag house filters. A differential pressure switch should be installed across the line filter to indicate when the filters need to be changed out due to plugging from normal usage. In the case of a bag rupture, the differential pressure switch would shut off the vacuum blower when the filters become plugged and sound an annunciator alarm indicating that an

emergency has occurred. The vacuum blower system would increase maintenance costs, but these would be offset by the annual energy savings.

5.1.4 Analysis

The existing steam jet vacuum system at the Area-A CHP uses approximately 22,500 lbm/hr of 300 psig steam (see Section 3.2.3.8). Two replacement options were evaluated:

- A vacuum blower system with a 50 hp electric motor. Vendor quotes resulted in an estimated cost of $12,968 for the unit.

- A liquid ring vacuum pump system with a 100 hp motor. Vendor quotes resulted in an estimated cost of $39,810 for the unit.

The liquid ring vacuum pump system was ruled out due to an initial cost of three times that of the vacuum blower system. The liquid ring vacuum pump system would also have a higher installation and maintenance cost due to the need of providing and maintaining liquid for the system.

The replacement of the steam jet vacuum system with the vacuum blower system would require approximately a two day shutdown of the fly ash removal system. The new vacuum blower system would be equipped with filters which must be replaced every 200 operating hours. Maintenance costs for filter replacement were estimated at $1,300 annually.

The vacuum blower system eliminates steam usage for the existing steam jet but results in additional electricity usage for the vacuum blower motor.

Annual coal savings are estimated at 8,820 MBtu. Additional electricity usage by the vacuum blower system was estimated at 56,721 kWh for an equivalent annual electric energy usage increase of 194 Mbtu.

5.1.5 Construction Cost

Construction cost of the vacuum blower system, including piping modification, electrical service, and associated equipment, was estimated at $31,300. The LCCID program adds design and SIOH (Supervision, Inspection, and Overhead incurred by the Government) costs to the construction cost to obtain the investment cost.

5.1.6 Life Cycle Cost Analysis

The annual energy savings, estimated construction costs, and maintenance costs were entered into the LCCID program with the following results.

Annual Electric Energy Savings (MBtu)	-194
Annual Coal Savings (MBtu)	8,820
Total Annual Energy Cost Savings	$10,119
Annual Maintenance Costs	$1,300
Electric Demand Cost Savings	0
Investment Cost	$34,868
SIR	4.1
Simple Payback	4.0

Supporting calculations, construction cost estimates, and life cycle cost analysis are contained in Appendix D.

5.1.7 <u>Recommendations</u>

Implement.

5.2 AREA-B INTERMEDIATE PRESSURE STEAM HEADER

5.2.1 Description

This ECO evaluates increasing the back pressure of the existing draft fan steam turbines in the Area-B CHP from low pressure to medium pressure, and using the exhaust steam to heat feedwater. The back pressure from the draft fan steam turbines is currently 5 psig which limits feedwater heating to 228°F. Under this ECO, the back pressure would be increased to about 75 psig and the higher temperature (320°F) exhaust steam used to heat feedwater to a higher temperature. The proposed feedwater heat exchanger would be installed upstream of the economizer.

5.2.2 Existing Condition

With the existing system, steam is exhausted to the low pressure steam header by the steam turbines used to drive the draft fans, feedwater pumps, and DA pump. The DA heater uses steam from the low pressure steam header to heat feedwater. The available low pressure steam exceeds the steam requirements of the DA heater when the boilers are operating at less than about 45% of capacity. Excess low pressure steam is vented to the atmosphere. The amount of low pressure steam vented was calculated with the Area-B computer boiler model for each month. Low pressure steam venting ranges from zero in the winter months to a peak of approximately 2,300 lbm/hr in the summer.

5.2.3 ECO Modification

For this ECO, a feedwater preheater would be installed upstream of the economizers between the DA heater and the boilers. The feedwater preheater would use steam from an intermediate pressure steam header supplied by the draft fan steam turbine exhaust. Figure 5-1 on the following page illustrates this ECO.

The use of low pressure steam for heating boiler feedwater is limited by the steam temperature in the low pressure steam header. The low pressure steam is currently used in the DA heater to heat boiler feedwater to 228°F. Heating of feedwater above 228°F requires higher temperature steam and corresponding higher pressures.

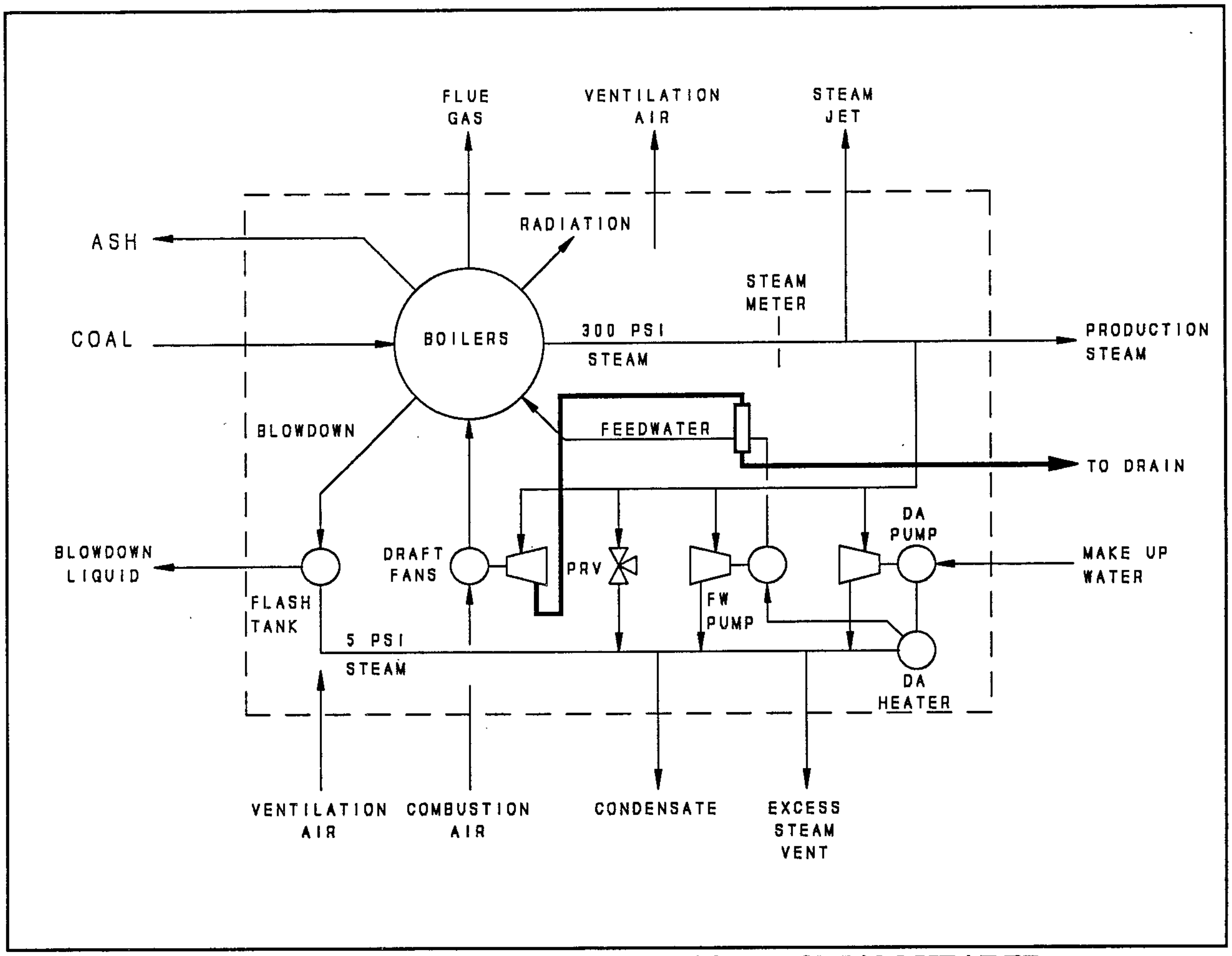

FIGURE 5-1. INTERMEDIATE PRESSURE STEAM HEADER

There are two options for obtaining higher temperature steam for feedwater heating:

- Option 1. The pressure and temperature in the existing low pressure steam header could be increased. This would result in higher back pressures for all of the steam turbines in the CHP. Back pressures for each steam turbine are limited by the design pressure of the exhaust casing. The exhaust casings on the draft fan steam turbines are currently rated for 75 psig, although the manufacturer indicates that they could likely be retested for 125 psig. The manufacturer of the DA pump steam turbines indicates that 25 psig is the maximum. The blowdown flash tank which also feeds the low pressure header is also likely limited to 25 psig. Based on the pressure limitations of existing equipment, raising the pressure of the existing low pressure steam header is not recommended.

- Option 2. The back pressure on each draft fan steam turbine could be increased and the steam exhaust routed to the new feedwater heater via an intermediate pressure steam header. The portion of the low pressure steam header collecting the exhaust

steam from the draft fan steam turbines would be converted to an intermediate pressure steam header. The steam turbines serving the feedwater and DA pumps, and the blowdown flash tank would not be modified. Excess steam from the intermediate pressure steam header would be piped to the low pressure steam header through a PRV station.

Option 2 is recommended because it does not require modification of existing steam turbines serving the feedwater and DA pumps, and the flash tank.

5.2.4 Analysis

The draft fan steam turbines operating with a back pressure of 5 psig will provide 550 hp with a steam rate of 21.6 lbm/hp-hr. The exhaust casing rating is 75 psig. With higher back pressures, the steam turbines must be renozzled to maintain 550 hp. The existing draft fan steam turbines with new nozzles operating with a back pressure of 75 psig will provide 550 hp with a steam rate of 45.5 lbm/hp-hr according to the manufacturer. The manufacturer indicates that the existing exhaust casing could be hydro tested for 125 psig. The draft fan steam turbines with new nozzles operating with a back pressure of 125 psig would provide 550 hp with a steam rate of 92.7 lbm/hp-hr.

The Area-B computer boiler model was modified to simulate a feedwater heater receiving steam from the draft fan steam turbines. A separate calculation was made for each month of the year and the results summed for the year. The results of the analysis are:

Back Pressure (psig)	Steam Temperature (°F)	Fan Turbine Steam Rate (lbm/hp-hr)	Annual Coal Usage (MBtu)	Annual Coal Savings (MBtu)
5	228	21.6	2,155,572	0
50	298	38.7	2,095,722	59,850
75	320	45.5	2,083,088	72,484
125	353	92.7	2,397,027	-241,455

Analysis indicated minimum annual fuel usage with a back pressure of 75 psig. Increasing steam turbine back pressure beyond 75 psig would increase venting of low pressure steam. Operating the draft fan steam turbines at a higher back pressure would generate additional low pressure steam at a rate greater than can be used for feedwater heating. However, boiler efficiency improvements offset the additional steam required to drive the draft fan steam turbines. The result is a net energy savings.

The following modifications would be necessary for this ECO:

- The nozzles in the draft fan steam turbines must be replaced for operation at a 75 psig back pressure. The relief valve and control valve at each draft fan steam turbine must also be replaced.
- A new 300 psig steam supply line to each draft fan steam turbine must also be installed. The higher back pressure nearly doubles the turbine steam required. The existing 4 inch steam supply line must be replaced with a 6 inch steam supply line.
- The feedwater heater must be installed and piped to the feedwater header and the new intermediate pressure steam header.
- A pressure reducing station must be installed to route excess intermediate pressure steam to the low pressure steam header.
- Condensate from the feedwater heater would be piped to a floor drain. Alternatively, condensate could be sparged back into the feedwater with the addition of a pumped condensate return system.

Annual coal savings were estimated at 72,484 Mbtu by the computer boiler model.

5.2.5 <u>Construction Cost</u>

A vendor quote was obtained for the new feedwater heater. Costs for renozzling the draft fan steam turbines were obtained from the manufacturer. The construction costs include costs for the extensive piping modification within the CHP.

Construction cost was estimated at $315,652. The LCCID program adds design and SIOH costs to the construction cost to obtain the investment cost.

5.2.6 Life Cycle Cost Analysis

The annual energy savings and estimated construction costs were entered into the LCCID program with the following results:

Annual Electric Energy Savings (MBtu)	0
Annual Coal Savings (MBtu)	72,484
Total Annual Energy Cost Savings	$90,605
Annual Maintenance Costs	$400
Electric Demand Cost Savings	0
Investment Cost	$351,952
SIR	4.1
Simple Payback	3.9

Supporting calculations, construction cost estimates, and the life cycle cost analysis are contained in Appendix E.

5.2.7 Recommendations

Implement Option-2 with a turbine back pressure of 75 psig..

5.3 AREA-B COMBUSTION AIR PREHEATERS

5.3.1 Description

This ECO consists of installing combustion air preheaters on the Area-B boilers with heat recovery coils downstream of the existing electrostatic precipitators and preheat coils in the combustion air duct downstream of the forced draft fan. Figure 5-2 below illustrates the proposed ECO.

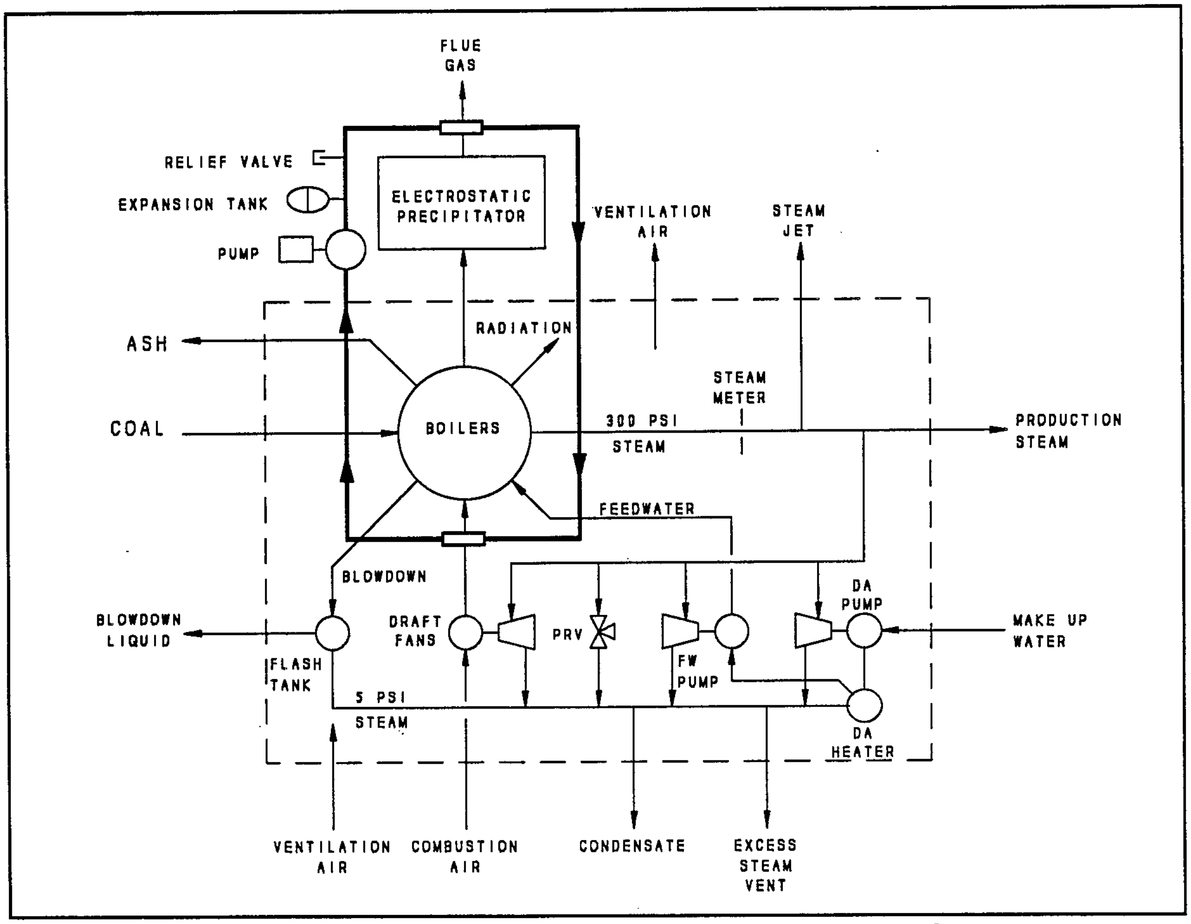

FIGURE 5-2. COMBUSTION AIR PREHEATERS

5.3.2 Existing Condition

Under average operating conditions there is 41,818 cfm of combustion air being supplied to each boiler at 56°F. There is 43,606 cfm of exhaust air leaving the economizer at 387°F. The lowest temperature of the flue gas to prevent formation of sulphuric acid is 280°F based on the amount of sulfur in the coal. This allows for a possible temperature differential of 107°F which could be utilized to increase the temperature of the combustion air.

5.3.3 ECO Modification

The ECO modification would be to install a run-around heat recovery loop with the heat recovery coil located on the exit of the electrostatic precipitator and the preheat coil located at 45 degrees in the junction of the forced draft duct and the supply air header. The heat recovery and preheat coils for each boiler would be piped into a heat recovery loop using 3 inch Schedule 80 steel pipe. The loop would include a 100 gpm pump, expansion tank, and relief valve. The pump and expansion tank would be located next to the induced draft fan, and the make-up water would come from the boiler feed water lines located on the wall behind the fans.

5.3.4 Analysis

The Area-B computer boiler model was modified to simulate combustion air preheaters which use heat from the flue gas to preheat combustion air. The computer boiler model indicated that in order to maintain 280°F flue gas temperature, this system can only be 30% effective. This produces a combustion air temperature of 154°F.

One problem with installing this system would be the increased static pressure on both the forced draft and induced draft fans. However, the increased combustion air temperature would result in reduced airflow rates at equivalent steam production. With the air preheater, required flow of the two fans are 39,410 and 41,092 cfm respectively, which is a 4.1% reduction in airflow rate. This reduced flow would decrease static pressure drop in the system by approximately 5.6 in. w.g. Actual static pressure drop across the proposed air preheater is 5.0 in. w.g.

Annual coal savings was calculated using the computer boiler model to first obtain coal usage at current average operating conditions. The computer boiler model was then changed to simulate operation with air preheaters which calculated the new coal usage. The difference is the coal energy saved.

Annual coal savings were estimated at 124,400 Mbtu.

5.3.5 Construction Cost

Vendor quotes were obtained for the coils used in the run-around heat recovery system, which comprises the air preheater. Additional costs for a pump, expansion tank, piping, and electrical service for the pump were also included.

Construction cost was estimated at $42,794 per boiler or a total of $195,947 for four boilers. The LCCID program adds design and SIOH costs to the construction cost to obtain the investment cost.

5.3.6 Life Cycle Cost Analysis

The annual energy savings and estimated construction costs were entered into the LCCID program with the following results:

Annual Electricity Savings (MBtu)	-10
Total Coal Savings (MBtu)	123,240
Total Annual Energy Cost Savings	154,017
Annual Maintenance Costs	$1,000
Electric Demand Cost Savings	0
Investment Cost	$218,482
SIR	11.3
Simple Payback	1.4

Supporting calculations, construction cost estimates, and the life cycle cost analysis are contained in Appendix F.

5.3.7 Recommendations

Implement.

5.4 AREA-B BLOWDOWN HEAT EXCHANGER

5.4.1 Description

This ECO consists of installing a heat exchanger to recover heat from the continuous blowdown on the Area-B boilers.

5.4.2 Existing Condition

Continuous blowdown from the boilers is piped to a flash tank which recovers flash steam for DA water heating. Blowdown liquid is piped to a floor drain. The blowdown rate was measured at 2.5% of the boiler steam production and averages 3,982 lbm/hr. (See Section 3.2.2.7 for discussion of the blowdown rate measurements.)

5.4.3 Proposed Modification

Under this ECO, a heat exchanger would be installed to recover heat from the blowdown liquid exiting the flash tank. The heat exchanger would be installed in the make-up boiler water line between the DA pump and the DA heater. Blowdown liquid from the flash tank would be piped to the shell side of the heat exchanger. Blowdown liquid exiting the heat exchanger would be piped to a floor drain. The heat exchanger would be installed on the operating floor level. Figure 5-3 on the following page illustrates this proposed ECO.

The heat exchanger should be sized for 600 gpm on the make-up water side and 15 gpm on the blowdown liquid side. The heat exchanger should have an effectiveness of 80% or be capable of exchanging 1.0 MBH of energy when operating between 56°F and 228°F. A heat exchanger bypass should be provided for use during mobilization.

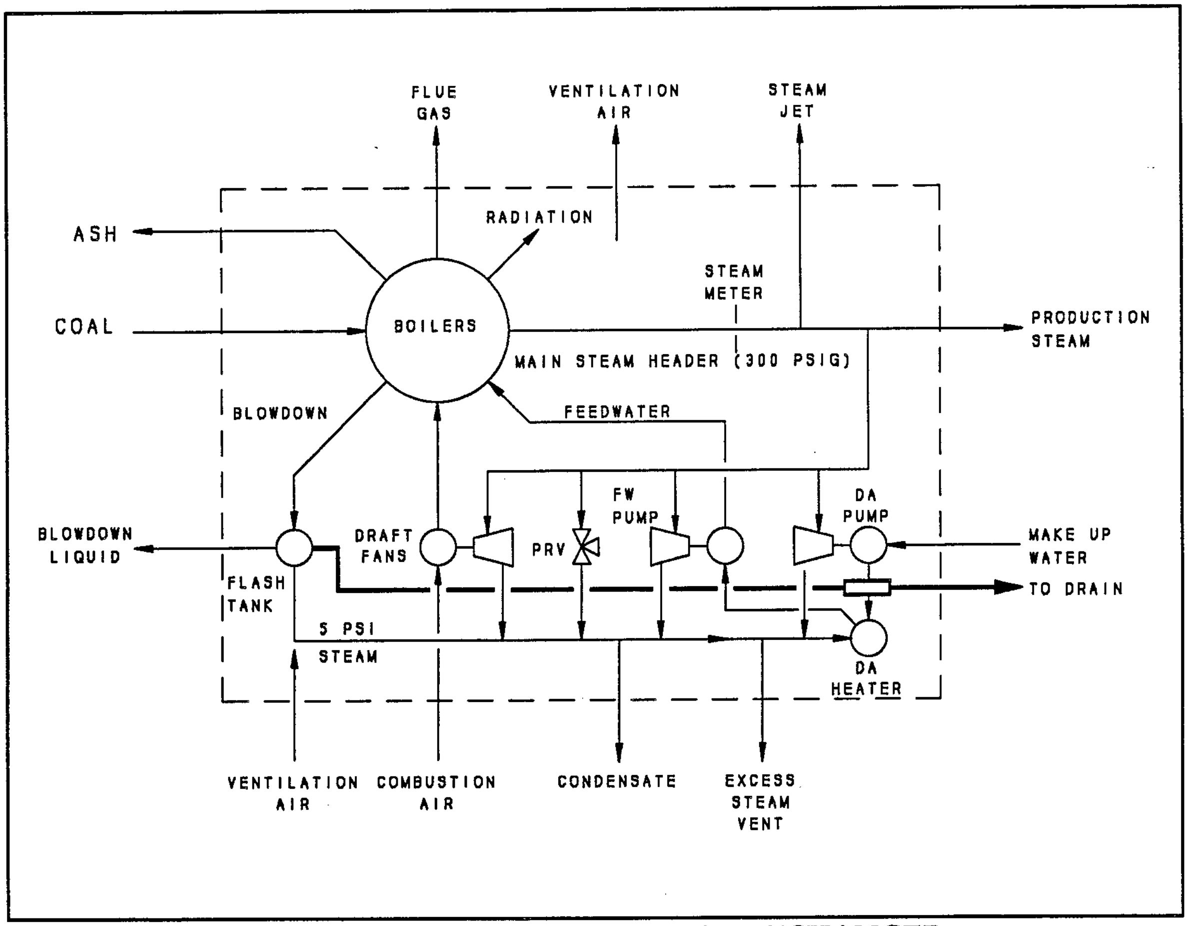

FIGURE 5-3. BLOWDOWN HEAT EXCHANGER

5.4.4 Analysis

The Area-B computer boiler model was modified to include the blowdown heat exchanger. The blowdown heat exchanger will add about 3.4°F to the make-up water temperature at average operating conditions.

The savings from the blowdown heat exchanger would be limited by the production and venting of excess low pressure steam. During the summer when excess low pressure steam is normally vented, energy savings from the blowdown heat exchanger would be offset by additional excess low pressure steam venting.

Annual coal savings was calculated using the computer boiler model to first obtain coal usage at current average operating conditions. The computer boiler model was then changed to simulate operation with the blowdown heat exchanger which calculated the new coal usage. The difference is the coal energy saved.

The annual coal savings were estimated at 2,556 MBtu.

5.4.5 Construction Cost

A vendor quote was obtained for the blowdown heat exchanger. Additional costs for the piping associated with the blowdown heat exchanger was included in the cost estimate.

The construction cost is estimated at $23,370. The LCCID program adds design and SIOH costs to the construction cost to obtain the investment cost.

5.4.6 Life Cycle Cost Analysis

The annual energy savings and estimated construction costs were entered into the LCCID program with the following results.

Annual Electricity Savings (MBtu)	0
Total Coal Savings (MBtu)	2,556
Total Annual Energy Cost Savings	$3,195
Annual Maintenance Costs	$400
Electric Demand Cost Savings	0
Investment Cost	$26,058
SIR	1.8
Simple Payback	9.3

Supporting calculations, construction cost estimates, and the life cycle cost analysis are contained in Appendix G.

5.4.7 Recommendations

Implement.

5.5 AREA-B CONDENSATE COLLECTION

5.5.1 Description

This ECO consists of installing a condensate collection system for condensate generated within the Area-B CHP.

5.5.2 Existing Condition

Due to possible explosive contamination, no condensate is returned from Area-B to the CHP. However, condensate generated within the CHP could be returned. Steam traps are located on the following components:

- Draft fan steam turbines
- DA pump steam turbines
- Feedwater pump steam turbines
- High pressure (300 psig) steam header
- Low pressure (5 psig) steam header

Condensate is currently routed to the wastewater treatment system via floor drains.

5.5.3 ECO Modification

Under this ECO, condensate would be collected and pumped to the make-up water tank. Condensate receivers would be placed at each steam trap likely to produce significant condensate. Pumps within the condensate receivers would pump the condensate to the make-up water tank via a new piping system.

5.5.4 Analysis

At average operating conditions, the amount of condensate generated by each component is as follows:

- Draft fan steam turbines have an exiting steam quality of 99.1% (0.9% of the steam entering the turbine is condensed). The resulting condensate generation is 175 lbm/hr for operation of two turbines.

- DA pump steam turbines exhaust superheated steam with no condensate generation.

- Feedwater pump steam turbines exhaust superheated steam with no condensate generation.

- High pressure (300 psig) steam header contains superheated steam with no condensate generation from pipe heat loss.

- Low pressure (5 psig) steam header also likely contains steam which is slightly superheated. The DA and feedwater pump steam turbines exhaust superheated steam into the header. Little or no condensate generation is expected.

Total condensate generation within the CHP is 175 lbm/hr. The condensate temperature from a vented condensate receiver would be a maximum of 200°F by the time it reaches the make-up water tank. Average make-up water flow is estimated at 143,463 lbm/hr at a temperature of 56°F. The combined temperature of the condensate and make-up water is calculated to be 56.2°F. In other words, the condensate will provide 0.2°F of make-up water heating. During periods of excess 5 psig steam venting, condensate heat recovered would be offset by additional steam venting.

Condensate recovery is estimated to save an average of 25,200 Btuh or 221 MBtu annually. At a steam cost of $1.77/MBtu, annual energy cost savings is $391. The installed cost of a single condensate receiver is $1,260. Installation of four condensate receivers, electrical service and a condensate piping system will result in a simple economic payback exceeding 25 years.

Backup data is contained in Appendix H.

5.5.5 Recommendations

A condensate collection system is not economically feasible.

5.6 AREA-A VACUUM PUMP

5.6.1 Description

This ECO consists of replacing the steam jet on the Area-A ash handling system with a vacuum pump system.

5.6.2 Existing Condition

The existing vacuum system consists of an orifice plate steam jet with six, 5/16 in. holes. The steam is currently supplied to the orifice plate by a 2 in. steam line at 400 psi. The system is currently operated two hours per day with the steam on 75% of the time. The average hourly steam usage is approximately 9,800 lbm/hr, which yields a daily average of 14,700 lbm/day.

5.6.3 ECO Modification

Analysis indicated that a vacuum blower system is more cost effective than a vacuum pump system. Under this ECO, the existing steam jet vacuum system would be replaced with a 50 hp vacuum blower system. Once the existing system is removed, the vacuum blower system would be installed in the same area where the steam jet vacuum system and air washer are presently located. Ash transport piping would be adapted to the vacuum blower system, and electrical service brought to the motor. A line filter should be placed upstream of the vacuum blower to protect it from any leakage and/or rupture of the bag house filters. A differential pressure switch should be installed across the line filter to indicate when the filters need to be replaced due to plugging from normal usage. In the case of a bag rupture, the differential pressure switch would shut off the vacuum blower when the filters become plugged and sound an annunciator alarm indicating that an emergency has occurred. The vacuum blower system would increase maintenance costs, but these would be offset by the annual energy savings.

5.6.4 Analysis

The existing steam jet vacuum system at the Area-A CHP uses approximately 14,700 lbm/hr of 400 psig steam (see Section 3.3.3.6). Two replacement options were evaluated:

- A vacuum blower system with a 50 hp electric motor. Vendor quotes resulted in a $12,968 cost for the unit.

- A liquid ring vacuum pump system with a 100 hp motor. Vendor quotes resulted in a $39,810 cost for the unit.

The liquid ring vacuum pump system was ruled out due to an initial cost of three times that of the vacuum blower system. The liquid ring vacuum pump system would also have a higher installation and maintenance cost due to the need of providing and maintaining a liquid for the system.

The replacement of the steam jet vacuum system with the vacuum blower system would require approximately a two day shutdown of the fly ash removal system. The new vacuum blower system would be equipped with filters which must be replaced every 200 operating hours. Maintenance costs for filter replacement was estimated at $650 annually.

The vacuum blower system eliminates steam usage for the existing steam jet but results in additional electricity usage for the vacuum blower motor.

Annual coal savings are estimated at 5,883 Mbtu based on elimination of the steam jet vacuum system. Additional electricity usage by the vacuum blower system is estimated at 28,360 kWh for an equivalent annual electric energy usage increase of 97 MBtu.

5.6.5 Construction Cost

Construction cost was estimated at $31,300. The LCCID program adds design and SIOH (Supervision, Inspection, and Overhead incurred by the Government) costs to the construction cost to obtain the investment cost.

5.6.6 Life Cycle Cost Analysis

The annual energy savings, estimated construction costs, and maintenance costs were entered into the LCCID program with the following results.

Annual Electric Energy Savings (MBtu)	-97
Total Coal Savings (MBtu)	5,883
Total Annual Cost Savings	$6,901
Annual Maintenance Costs	$650
Electric Demand Cost Savings	0
Investment Cost	$34,900
SIR	2.9
Simple Payback	5.6

Supporting calculations, construction cost estimates, and life cycle cost analysis are contained in Appendix D.

5.6.7 Recommendations

Implement.

5.7 AREA-A ELECTRIC DA PUMP

5.7.1 Description

This ECO evaluates installing a small auxiliary DA pump to bypass the large existing DA pump during normal operation.

5.7.2 Existing Condition

A 100 hp electric DA pump is used to convey water from the makeup water tank to the DA heater. This 100 hp DA pump is sized for mobilization capacity. Under average operating conditions the DA pump runs at about 20% capacity. The DA pump curve indicates that the DA pump is operating at a 40% efficiency as opposed to 85% when fully loaded.

5.7.3 ECO Modification

Under this ECO, the 100 hp DA pump would remain but be taken off line. A new 15 hp auxiliary DA pump sized for current peak operating conditions would be piped into the system as a bypass to the larger DA pump. Peak steam demand at current operating conditions is estimated at 162,700 lbm/hr with a resulting feedwater flow rate of 325 gpm. The modification would allow for the smaller, more efficient auxiliary DA pump to be operated throughout the year, thereby producing an energy savings due to both increased efficiency and smaller pump size.

5.7.4 Analysis

The 100 hp DA pump was originally sized for a mobilization capacity of 1750 gpm at 185 ft. of head. Under current operating conditions the isolation valve on the DA pump discharge is open only a fraction of a turn, thereby causing the pump to operate at an average capacity of approximately 200 gpm. At these conditions the DA pump is operating at a 30% efficiency, with a measured power consumption of 43.4 kW.

The 100 hp DA pump would be bypassed by a 350 gpm auxiliary DA pump operating at 100 ft of head. This auxiliary DA pump would have an average power consumption of 12.4 kW. The auxiliary pump would provide sufficient flow for the Area-A boilers throughout the year.

The new auxiliary DA pump could be located between the draft fan steam turbine and the back wall of the Area-A CHP near the motor starters. This auxiliary DA pump would have an isolation valve so that it can be isolated from the system, and a bypass loop to prevent deadheading. The installation of the new auxiliary DA pump would require that the existing system be shut down for approximately 8 hours so that the suction line could be tied into existing pipe. One possible way to install this line, without shutting down the boilers, would be to pick a low production time and use the emergency river water as make up water for the DA heaters. The discharge line could then be tied in without shutting down the system by using the steam DA pump during the tie in period.

Electric energy savings would be the difference in power consumption of the existing 100 hp DA pump and the new 15 hp auxiliary DA pump which draws 31 kW. The DA pump operates 8760 hours per year.

The annual electricity savings were estimated at 271,560 kWh for an equivalent annual electric energy savings of 927 MBtu.

5.7.5 Construction Cost

Construction cost estimates include the cost of the new 15 hp DA pump, associated piping, and electric service for the DA pump.

The construction cost was estimated at $19,179. The LCCID program adds design and SIOH costs to the construction cost to obtain the investment cost.

5.7.6 Life Cycle Cost Analysis

The annual energy savings and estimated construction costs were entered into the LCCID program with the following results.

Annual Electricity Savings (MBtu)	927
Total Coal Savings (MBtu)	0
Total Annual Energy Cost Savings	$4,329
Annual Maintenance Costs	$400
Electric Demand Cost Savings	$3,534
Investment Cost	$21,400
SIR	4.2
Simple Payback	2.9

Calculations and other backup material are included in Appendix I.

5.7.7 Recommendations

Implement.

5.8 AREA-A AIR PREHEATERS

5.8.1 Description

This ECO evaluates the use of excess low pressure (5 psig) steam to preheat the combustion air for the Area-A boilers.

5.8.2 Existing Condition

Under current operating conditions, two boilers are operational at any one time, with a rotation occurring among four boilers total. At average operating conditions there is an excess of 7,439 lbm/hr of low pressure steam being ventilated to the atmosphere. Each boiler is currently using 32,126 cfm of combustion air at 56°F and consuming 76 MBtuh of coal, for a total consumption of 152 MBtuh.

5.8.3 ECO Modification

This ECO is to place a steam coil in the combustion air duct, downstream of the forced draft fan of each of the four boilers. Figure 5-4 illustrates the proposed ECO. The best location for this coil would be where the combustion air duct from the forced draft fan joins into the supply air header for the boiler. At this location the coil could be inserted at 45° for a maximum coil size of 60 x 94 inches. The steam for the coil would come from the low pressure steam header located on the wall behind the draft fans. The steam line serving the coil would contain only a shut off valve and no modulating control valve. The condensate from the coil would be piped through a steam trap and then to the drain, common with that of the draft fan steam turbine.

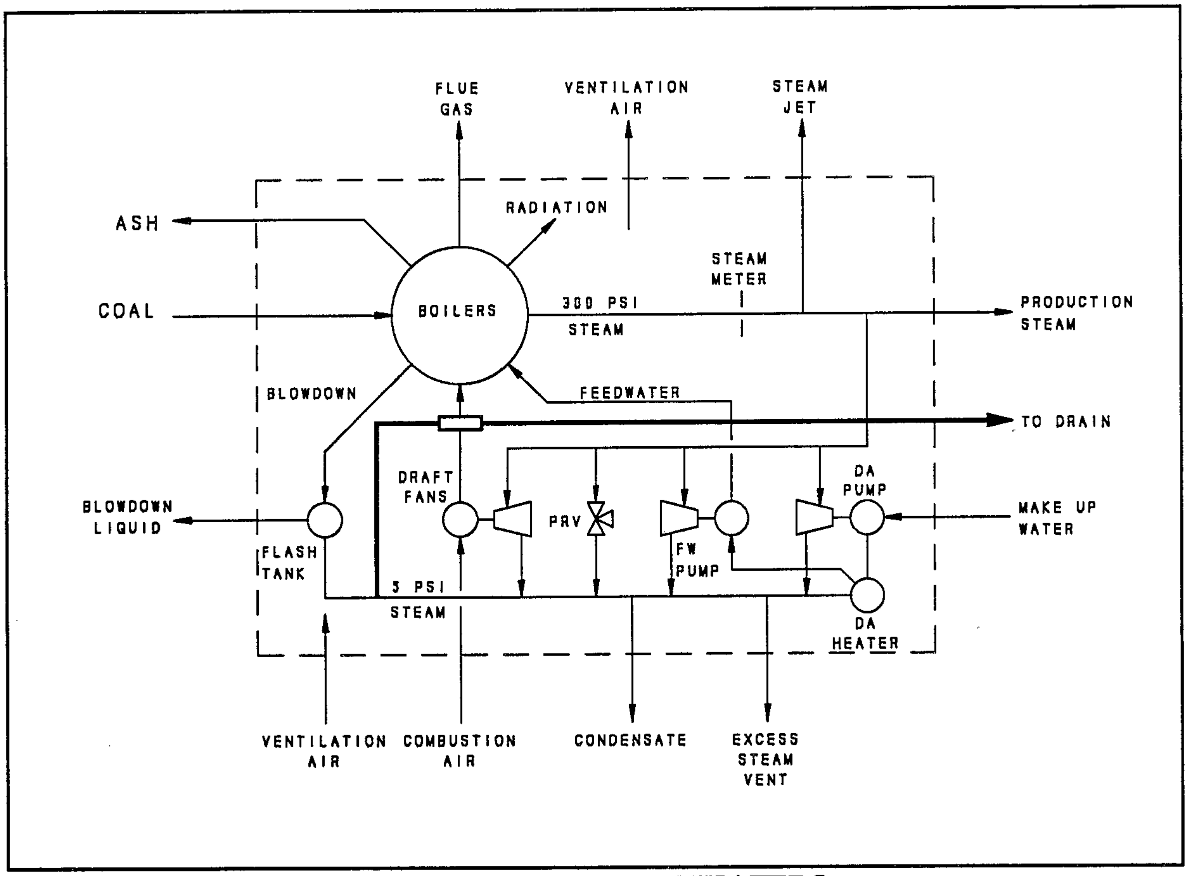

FIGURE 5-4. AIR PREHEATERS

5.8.4 Analysis

The insertion of a steam coil into the combustion air duct would increase the static pressure on the forced draft fan. The forced draft fan is currently operating at maximum speed, so speed cannot be increased to accommodate the increase in static pressure. Replacing the forced draft fan and associated steam turbine would be expensive. However, with careful design the static pressure limitations can be avoided.

To minimize the static pressure increase, a single row steam coil was selected which had a 0.22 inch water column static pressure drop. This coil would produce an average combustion air temperature of 136°F with a coil effectiveness of 46%. Currently, the average combustion air temperatures are 56°F.

The Area-A computer boiler model was modified to simulate the air preheater. Inputting the above coil parameters into the computer boiler model resulted in a 7% increase in boiler efficiency. The increase in boiler efficiency resulted in a decrease in required combustion air flow from 32,125 to 29,430 cfm at average operating conditions. The estimated decrease in static pressure at the lower combustion air flow is about 5.0 inches water column. Therefore, the air preheater would actually decrease the static pressure requirements on the fans for equivalent steam production.

The computer boiler model calculates low pressure (5 psig) steam requirements for the air preheater to be 3,930 lbm/hr at average operating conditions. Excess low pressure steam venting at average operating conditions was calculated to be 7,439 lbm/hr. Thus, excess low pressure steam is available in sufficient quantities to supply the air preheater.

Annual coal savings was calculated using the computer boiler model to first obtain coal usage at current average operating conditions. The computer boiler model was then changed to simulate operation with air preheaters which calculated the new coal usage. The difference equals coal energy saved.

The annual coal savings are estimated at 113,880 Mbtu.

5.8.5 Construction Cost

The construction cost estimate included the costs of steam coils and associated piping for four boilers. The construction cost was estimated at $70,605. The LCCID program adds design and SIOH costs to the construction cost to obtain the investment cost.

5.8.6 Life Cycle Cost Analysis

The annual energy savings and estimated construction costs were entered into the LCCID program with the following results.

Annual Electricity Savings (MBtu)	0
Annual Coal Savings (MBtu)	113,900
Total Annual Energy Cost Savings	$142,350
Annual Maintenance Costs	$1,000
Electric Demand Cost Savings	0
Investment Cost	$78,700
SIR	28.9
Simple Payback	0.6

Supporting calculations, construction cost estimates, and the life cycle cost analysis are contained in Appendix J.

5.8.7 Recommendations

Implement.

5.9 AREAS-A AND B INLET AIR DAMPERS

5.9.1 Description

This ECO consists of installing manually controlled inlet air dampers in the roof openings over the boilers. These dampers would be used to restrict the openings in the winter so that the warmer air from the upper level of the boiler plant would be pulled down by the forced draft fans. Higher temperature combustion air would result, and this would result in higher boiler efficiency. The dampers would be left open for ventilation in the summer. This ECO applies to both Area-A and Area-B central heating plants (CHP).

5.9.2 Existing Condition

Both CHPs have roof openings above each boiler. Each roof opening is roughly 8 by 12 feet. There are presently no dampers for controlling air flow through these openings.

Each of the CHPs are normally operated with two boilers. The remaining boilers are left idle. The draft fan on each boiler draws combustion air from the lowest level in the CHP. The boilers are located on the levels above, so the lowest level receives little heat gain from the boiler. Combustion and ventilation air enter the CHP primarily through the roof openings and the truck door on the lowest level. The truck door is closed in the winter, but left open in the summer for ventilation. With all roof openings open, most of the combustion air enters the CHP through the openings above the cold boilers where it drops to the lowest level without picking up any heat and is drawn into the forced draft fan. The buoyant force of the air above the hot boilers causes flow out through the roof openings rather than in. The result of this arrangement is that heat loss from the boilers is lost through the roof openings and combustion air temperature is essentially the same as the ambient temperature.

5.9.3 ECO Modification

Under this ECO, operable dampers would be installed in each of the roof openings. During winter operation, only dampers above operating boilers would be opened; dampers over cold boilers would be closed. Air entering the CHP would then flow down over the hot boilers using boiler heat loss to preheat combustion air. Figure 5-5 on the following page illustrates this proposed ECO. During the summer, this strategy would likely result in room air temperatures in the CHP in excess of 120°F which would be too hot for the operating personnel. During warm weather additional dampers would be opened to prevent overheating.

The operable dampers for each roof opening would consist of operable louvers equipped with pneumatic operators and a pneumatic open/close switch on the firing floor for each roof opening.

Each roof opening would require an 8 x 12 ft damper. The dampers would likely be fabricated in 4 x 12 ft modules. Two pneumatic operators per roof opening were assumed.

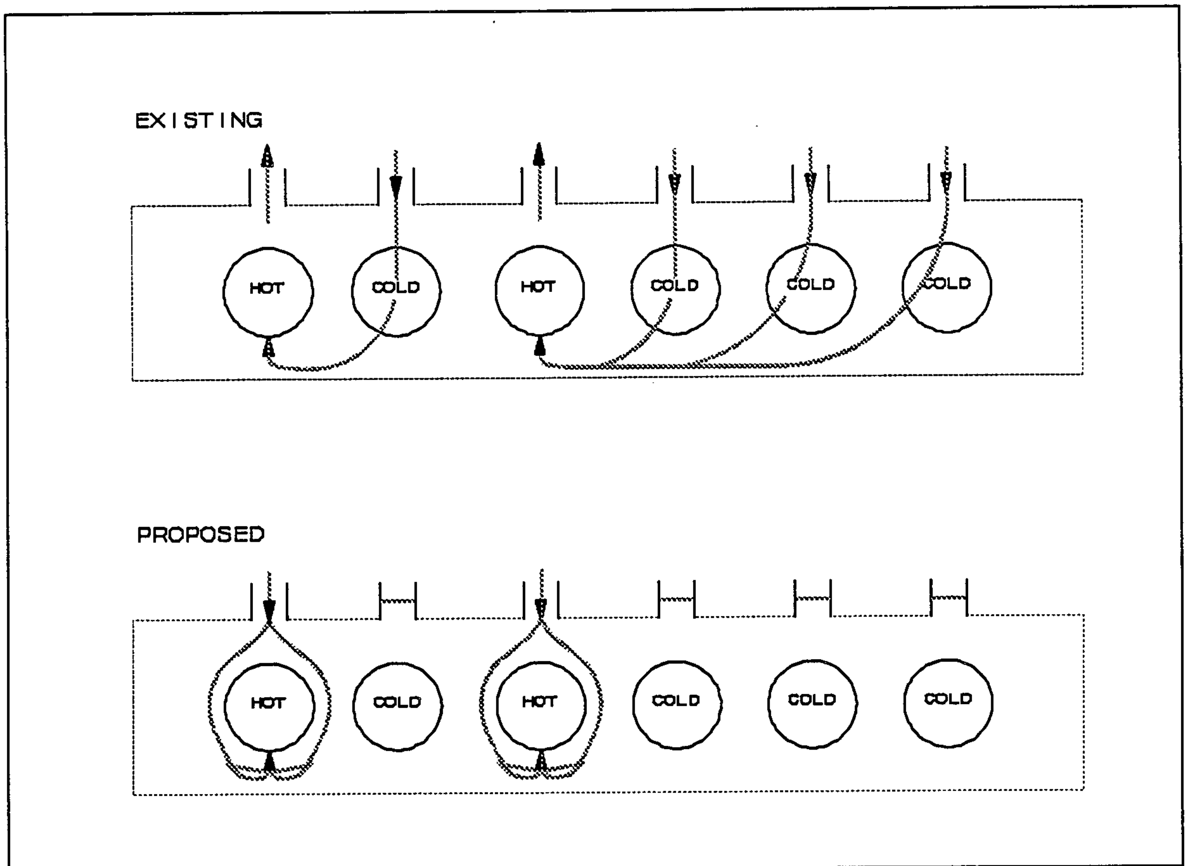

FIGURE 5-5. INLET AIR DAMPERS

5.9.4 Analysis

Heat loss from boilers is typically 1% to 2% of peak boiler capacity. Using the full boiler capacity of 161,800 lbm/hr and assuming 1% heat loss, the resulting heat loss from each boiler is 1.65 MBH. Heat loss from two boilers is 3.29 MBH.

During the field survey the Area-B CHP was operating near the annual average rate of steam production. Ambient temperature and the temperature on the lowest level was 60°F. Room temperature on the firing floor was about 70°F and temperatures on the upper levels near the operating boilers were 90°F. From this data, it was concluded that at the existing condition, combustion air temperature is approximately equal to ambient temperature. It was also concluded that room temperature on the firing floor was the weighted average of the air temperature of the lowest level and the air temperature on the upper levels.

Using the 3.29 MBH figure and the 30°F differential observed from the lowest to the highest level, the flow past each boiler is calculated to be 51,000 cfm. The air flow velocity through each roof opening is then 531 fpm which is a reasonable number for free convection.

Using the data and assumptions developed above and average monthly ambient temperatures; monthly combustion air, room, and exhaust temperatures were predicted and averaged. The average combustion temperature was the same as the average ambient temperature at 56°F. Room temperatures on the firing floor ranged from 45° to 85°F with the average at 66°F. Exhaust temperatures averaged 86°F.

The Areas-A and B computer boiler model was then modified to reflect the proposed modifications. Air entering the CHP was assumed to be restricted to only that necessary for combustion. It was assumed that all dampers would be closed except for those above each boiler. The result is that most of the air used for combustion would be drawn down past the hot boilers picking up the radiation heat.

Calculating the average combustion air flow for each month and assuming constant boiler heat loss; monthly combustion air and room temperatures were predicted and averaged. Room temperatures on the firing floor were assumed to be equal to the combustion air temperature. Combustion air temperatures ranged from 64° to 118°F with the average at 92°F.

Year round operation of the system with dampers open only over the operating boilers results in high temperatures in the CHP during the summer. Average room temperature in July was 118°F. To prevent overheating, dampers over cold boilers must be modulated to maintain acceptable room temperatures in the CHP. It was assumed that dampers would be modulated to control room temperatures at 80°F. The resulting combustion air temperatures ranged from 64° to 80°F with the average at 76°F. Room temperatures ranged from 64° to 85°F. Figure 5-6 on the following page is a graphical representation of the results of the calculations.

The new average annual combustion air temperature was input to the computer boiler model and average annual performance computed. Raising the average combustion air temperature from 56° to 76°F in the Area-B CHP resulted in an average boiler efficiency increase from 71.5% to 73.3%. This efficiency increase is close to the rule of thumb prediction of a 1% efficiency improvement for every 40°F increase in combustion air temperature.

The efficiency improvement results in a reduction in coal usage at Area-B of 25,404 MBtu annually. Applying the same analysis to Area-A results in a reduction in coal usage of 17,500 MBtu annually. Total savings for both Areas-A and B is 42,924 MBtu.

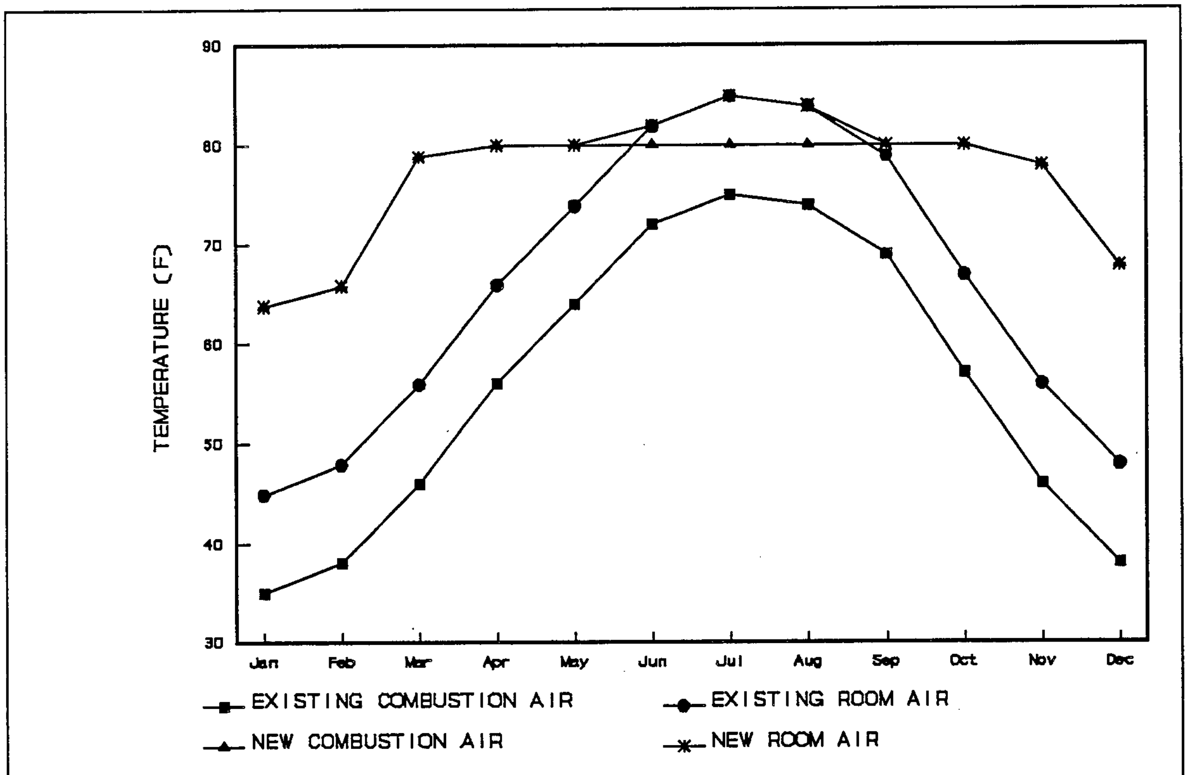

FIGURE 5-6. CALCULATED COMBUSTION AIR TEMPERATURE RESULTS

5.9.5 Construction Cost

Construction costs were estimated based on the installation of 12 x 8 ft operable louvers in each roof opening with two pneumatic operators per louver. Operable louvers rather than dampers were selected due to their heavier construction. Construction cost estimates included the cost of running pneumatic tubing to the pneumatic operators and operating switches on the firing floor.

The construction cost was estimated at $86,720. The LCCID program adds design and SIOH costs to the construction cost to obtain the investment cost.

5.9.6 Life Cycle Cost Analysis

The annual energy savings and estimated construction costs were entered into the LCCID program with the following results.

Annual Electricity Savings (MBtu)	0
Annual Coal Savings (MBtu)	42,924
Total Annual Energy Cost Savings	$53,655
Annual Maintenance Costs	$400
Electric Demand Cost Savings	0
Investment Cost	$96,700
SIR	8.9
Simple Payback	1.8

Supporting calculations, construction cost estimates, and the life cycle cost analysis are contained in Appendix K.

5.9.7 Recommendations

Implement.

SECTION 6.0

SUMMARY AND RECOMMENDATIONS

6.1 RECOMMENDATIONS

Table 6-1 presents the results of the life cycle cost analysis for the recommended ECOs (listed in order of economic benefit). The only ECO analyzed under this study which is not recommended is the Area-B Condensate Collection ECO.

TABLE 6-1
RECOMMENDED ECOS

Energy Conservation Opportunity	Annual Electric Savings (MBtu)	Annual Coal Savings (MBtu)	Annual Energy Cost Savings ($)	Annual Electric Demand Savings ($)	Annual Maint. Cost Savings ($)	Invest-ment Cost ($)	SIR	Simple Payback (yrs)
Area-A Air Preheaters	0	113,900	142,350	0	(1,000)	78,700	28.9	0.6
Area-B Air Preheater	(10)	123,240	154,000	0	(1,000)	218,500	11.3	1.4
Inlet Air Dampers	0	42,924	53,655	0	(400)	96,700	8.9	1.8
Area-A Electric DA Pump	927	0	4,329	3,534	(400)	21,400	4.2	2.9
Area-B Steam Header	0	72,484	90,605	0	(400)	352,000	4.1	3.9
Area-B Vacuum Pump	(194)	8,820	10,119	0	(1,300)	34,900	4.1	4.0
Area-B Cogeneration	24,307	(14,045)	95,957	92,682	(6,400)	927,000	2.4	4.6
Area-A Vacuum Pump	(97)	5,883	6,901	0	(650)	34,900	2.9	5.6
Area-B Blowdown Heat Exchanger	0	2,556	3,195	0	(400)	26,100	1.8	9.3
TOTAL SAVINGS	33,902	355,762	602,997	130,416	(58,326)	1,698,200		
PERCENT SAVINGS	14.2	10.8	11.5	11.7				
NEW ENERGY USAGE	204,186	2,941,918	4,631,020	980,628				
PRESENT ENERGY USAGE	238,098	3,297,680	5,234,017	1,111,044				

6.2 TOTAL ENERGY SAVINGS

The summary of energy use and cost before and after implementation of all ECOs recommended in this report is shown in Table 6-2 below.

TABLE 6-2
TOTAL ENERGY SAVINGS

	Annual Electric Energy (MBtu)	Annual Electric Demand ($)	Annual Coal Energy (MBtu)	Total Annual Energy* ($)
BEFORE	238,098	1,111,044	3,297,680	6,345,061
AFTER	213,165	1,014,828	2,941,918	5,687,734
SAVINGS	24,933	96,216	355,762	653,327

*Includes energy and electric demand charges.

APPENDIX A

SCOPE OF WORK AND CONFIRMATION NOTICES

CESAM-EN-CC

December 1990
* Revised 30/31 July 1991

APPENDIX "A"

SCOPE OF WORK

FOR

LIMITED ENERGY STUDIES

AT

HOLSTON ARMY AMMUNITION PLANT, TENNESSEE

Performed as part of the

ENERGY ENGINEERING ANALYSIS PROGRAM (EEAP)

* Revisions are underlined.

SCOPE OF WORK
FOR
LIMITED ENERGY STUDIES
AT
HOLSTON ARMY AMMUNITION PLANT, TENNESSEE

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ANNEXES

A - DETAILED SCOPE OF WORK

B - EXECUTIVE SUMMARY GUIDELINE

1. <u>BRIEF DESCRIPTION OF WORK</u>: The Architect-Engineer (AE) shall:

1.1 Review the previously completed energy study for the applicable system covered by this study.

1.2 Perform a site survey of specific buildings or areas sufficient to collect all data required to evaluate the specific energy conservation opportunities (ECOs) included in this study.

1.3 Evaluate specific ECOs to determine their energy savings potential and economic feasibility.

1.4 Prepare a comprehensive report to document all work performed, the results and all recommendations. A separate report shall be prepared for each increment of work awarded from among the ECOs in ANNEX A, DETAILED SCOPE OF WORK.

2. <u>GENERAL</u>

2.1 This study is limited to the evaluation of the specific buildings, systems, or ECOs listed in Annex A, DETAILED SCOPE OF WORK.

2.2 The information and analysis outlined herein are considered to be minimum requirements for adequate performance of this study.

2.3 For the buildings, systems or ECOs listed in the detailed scope of work, all methods of energy conservation which are reasonable and practical shall be considered, including improvements of operational methods and procedures as well as the physical facilities. All energy conservation opportunities which produce energy or dollar savings shall be documented in the report. Any energy conservation opportunity considered infeasible shall also be documented in the report with reasons for elimination.

2.4 The study shall consider the use of all energy sources applicable to each building, system, or ECO.

2.5 The "Energy Conservation Investment Program (ECIP) Guidance", described in letter from CEHSC-FU, dated 25 April 1988 and the latest revision from CEHSC-FU establishes criteria for ECIP projects and shall be used for performing the economic analyses of <u>all</u> ECOs and projects. The program, Life Cycle Cost In Design (LCCID), has been developed for performing life cycle cost calculations in accordance with ECIP guidelines and is referenced in the ECIP Guidance. If any program other than LCCID is proposed for life cycle cost analysis, it must use the mode of calculation specified in the ECIP Guidance. The output must be in the format of the ECIP LCCA summary sheet, and it must be submitted for approval to the Contracting Officer.

2.6 The following definitions apply to terms used in this scope of work:

2.6.1 "Contracting Officer", "Contracting Officer's Representative", or Government's Representative" refer to the contracting office of the Mobile District, U. S. Army Corps of Engineers.

2.6.2 "Installation Commander", or "Installation Representative" refer to the military commander of Holston Army Ammunition Plant.

2.6.3 "Plant Manager", Operating Contractor", or "Operating Contractor's Representative" refer to the Holston Defense Corporation, which operates Holston Army Ammunition Plant under contract to the U. S. Army.

3. <u>PROJECT MANAGEMENT</u>

3.1 <u>Project Managers</u>. The AE shall designate a project manager to serve as a point of contact and liaison for work required under this contract. Upon award of this contract, the individual shall be immediately designated in writing. The AE's designated project manager shall be approved by the Contracting Officer prior to commencement of work. This designated individual shall be responsible for coordination of work required under this contract. The Contracting Officer will designate a project manager to serve as the Government's point of contact and liaison for all work required under this contract. This individual will be the Government's representative.

3.2 <u>Installation Assistance</u>.

a. The Installation Commander will designate an individual to coordinate between the AE and the Holston Defense Corporation. This individual will be the Installation Representative, and all correspondence with Holston Army Ammunition Plant will be addressed to his attention.

b. The Plant Manager will designate an individual to assist the AE in obtaining information and establishing contacts necessary to accomplish the work required under this contract. This individual will be the Operating Contractor's Representative.

3.3 <u>Public Disclosures</u>. The AE shall make no public announcements or disclosures relative to information contained or developed in this contract, except as authorized by the Contracting Officer.

3.4 <u>Meetings</u>. Meetings will be scheduled whenever requested by the AE or the Contracting Officer for the resolution of questions or problems encountered in the performance of the work. The AE's project manager and the Government's representative shall be

required to attend and participate in all meetings pertinent to the work required under this contract as directed by the Contracting Officer. These meetings, if necessary, are in addition to the presentation and review conferences.

3.5 Site Visits, Inspections, and Investigations. The AE shall visit and inspect/investigate the site of the project as necessary and required during the preparation and accomplishment of the work.

3.6 Records

3.6.1 The AE shall provide a record of all significant conferences, meetings, discussions, verbal directions, telephone conversations, etc., with Government representative(s) relative to this contract in which the AE and/or his designated representative(s) participated. These records shall be dated and shall identify the contract number, and modification number if applicable, participating personnel, subject discussed and conclusions reached. The AE shall forward to the Contracting Officer within ten calendar days, a reproducible copy of the records.

3.6.2 The AE shall provide a record of requests for and/or receipt of Government-furnished material, data, documents, information, etc., which if not furnished in a timely manner, would significantly impair the normal progression of the work under this contract. The records shall be dated and shall identify the contract number and modification number, if applicable. The AE shall forward to the Contracting Officer within ten calendar days, a reproducible copy of the record of request or receipt of material.

3.7 Interviews. The AE and the Government's representative shall conduct entry and exit interviews with the Plant Manager before starting work at the installation and after completion of the field work. The Government's representative shall schedule the interviews at least one week in advance. Separate entry and exit interviews will be held for each increment of work awarded from among the ECOs in ANNEX A, DETAILED SCOPE OF WORK.

3.7.1 Entry. The entry interview shall describe the intended procedures for the survey and shall be conducted prior to commencing work at the facility. As a minimum, the interview shall cover the following points:

a. Schedules.

b. Names of energy analysts who will be conducting the site survey.

c. Proposed working hours.

d. Support requirements from Holston Defense Corporation (HDC).

3.7.2 Exit. The exit interview shall briefly describe the items surveyed and probable areas of energy conservation. The interview shall also seek input and advice from the Plant Manager.

4. SERVICES AND MATERIALS. All services, materials (except those specifically enumerated to be furnished by the Government), plant, labor, supervision and travel necessary to perform the work and render the data required under this contract are included in the lump sum price of the contract.

5. DETAILED SCOPE OF WORK. The Detailed Scope of Work is contained in Annex A.

6. WORK TO BE ACCOMPLISHED.

6.1 Review Previous Studies. Review the previous energy study which applies to the specific system covered by this study. This review will acquaint the AE with the work that has been performed previously and may supply some of the information needed to develop the ECOs in this study.

6.2 Perform a Limited Site Survey. For each increment awarded, the AE shall obtain all necessary data to evaluate the applicable ECOs or projects by conducting a site survey. However, the AE is encouraged to use any data that may have been documented in a previous study. The AE shall document his site survey on forms developed for the survey, or standard forms, and submit these completed forms as part of the report. All test and/or measurement equipment shall be properly calibrated prior to its use.

6.3 Evaluate Selected ECOs. For each increment awarded, the AE shall analyze the applicable ECOs from Annex A. These ECOs shall be analyzed in detail to determine their feasibility. Savings to Investment Ratios (SIRs) shall be determined using current ECIP guidance. The AE shall provide all data and calculations needed to support the recommended ECO. All assumptions and engineering equations shall be clearly stated. Calculations shall show how all numbers in the ECO were figured and shall be an orderly step-by-step progression from the first assumption to the final number. Descriptions of products, manufacturers catalog cuts, pertinent drawings and sketches shall also be included. A life cycle cost analysis summary sheet shall be prepared for each ECO and included as part of the supporting data.

6.4 Submittals, Presentations and Reviews. The work accomplished for each delivery order awarded shall be fully documented by a comprehensive report. The report shall have a table of contents and shall be indexed. Tabs and dividers shall clearly and distinctly divide sections, subsections, and appendices. All pages shall be numbered. Names of the persons primarily responsible for the project shall be included. The AE shall give a formal presentation of the interim submittal to installation, command, and other

Government personnel. Slides or view graphs showing the results of the study to date shall be used during the presentation. During the presentation, the personnel in attendance shall be given ample opportunity to ask questions and discuss any changes deemed necessary to the study. A review conference will be conducted the same day, following the presentation. Each comment presented at the review conference will be discussed and resolved or action items assigned. It is anticipated that the presentation and review conference will require approximately one working day. The presentation and review conference will be at the installation on the date agreeable to the Plant Manager, the AE and the Government's representative. The Contracting Officer may require a resubmittal of any document(s), if such document(s) are not approved because they are determined by the Contracting Officer to be inadequate for the intended purpose.

6.4.1 Interim Submittal. An interim report shall be submitted for review after the field survey has been completed and an analysis has been performed on all of the ECOs. The report shall indicate the work which has been accomplished to date, illustrate the methods and justifications of the approaches taken and contain a plan of the work remaining to complete the study. Calculations showing energy and dollar savings, SIR, and simple payback period of all the ECOs shall be included. The results of the ECO analyses shall be summarized by lists as follows:

a. All ECOs which the AE has considered and eliminated without formal analysis shall be grouped into one listing with reasons and justifications for their elimination.

b. All ECOs which were analysed shall be grouped into two listings, recommended and non-recommended, each arranged in order of descending SIR. These lists may be subdivided by building or area as appropriate for the study.

The AE shall submit the Scope of Work and any modifications to the Scope of Work as an appendix to the report. A narrative summary describing the work and results to date shall be a part of this submittal. The survey forms completed during this audit shall be submitted with this report. The survey forms only may be submitted in final form with this submittal. They should be clearly marked at the time of submission that they are to be retained. They shall be bound in a standard three-ring binder which will allow repeated disassembly and reassembly of the material contained within.

6.4.2 Final Submittal. The AE shall prepare and submit the final report when all sections of the report are 100% complete and all comments from the interim submittal have been resolved. The AE shall submit the Scope of Work for the study and any modifications to the Scope of Work as an appendix to the submittal. The report shall contain a narrative summary of conclusions and recommendations, together with all raw and supporting data, methods

used, and sources of information. The report shall integrate all aspects of the study. The lists of ECOs specified in paragraph 6.4.1 shall also be included. The final report and all appendices shall be bound in standard three-ring binders which will allow repeated disassembly and reassembly. The final report shall be arranged to include:

a. An Executive Summary to give a brief overview of what was accomplished and the results of this study using graphs, tables and charts as much as possible (See Annex B for minimum requirements).

b. The narrative report describing the problem to be studied, the approach to be used, and the results of this study.

c. Appendices to include as a minimum:

1) Energy cost development and backup data

2) Detailed calculations

3) Cost estimates

4) Computer printouts (where applicable)

5) Scope of Work

ANNEX A

DETAILED SCOPE OF WORK

1. All of the facilities to be studied in this contract are located at Holston Army Ammunition Plant (HSAAP) in Kingsport, Tennessee. Holston Army Ammunition Plant is a government-owned, contractor-operated (GOCO) facility. The operating contractor is the Holston Defense Corporation (HDC). Some of the facilities are located in Area A and some in Area B; Area A and Area B are separated by approximately five miles. For reasons of safety and security, access to both areas is controlled. Temporary passes will be required for both personnel and vehicle access.

a. Three weeks notice should be given by the AE prior to any visit. This time will be needed to make the necessary arrangements for the visit.

b. The AE should submit a list of the equipment and instruments they plan to use prior to their arrival. Because of the nature of HSAAP operations, safety regulations prohibit and restrict the use of some equipment on the installation. Having a list of the equipment to be used beforehand, HSAAP will be better prepared at the entrance interview to address the regulations pertaining to the equipment to be used. This will also facilitate coordination of the inspection and permitting of the equipment.

2. The AE shall provide all necessary effort, services, and materials required to accomplish the work specified.

3. The following persons have been designated as points of contact and liaison for all work required under this contract. Mr. Scott Shelton shall be the Installation Representative, and Mr. J. L. Bouchillon shall be the Operating Contractor's Representative.

4. The work in this annex is divided into increments. Depending upon the availability of funds and the customer's priorities, all or any combination of these increments may be awarded as the base contract. If all of the increments cannot be awarded initially, subsequent increments may be awarded as modifications to the contract when funds become available.

5. Completion Schedule: The completion schedule for each increment awarded under this scope of work will be negotiated prior to the award, but the completion date for any increment shall not be later than 270 days after Notice-to-Proceed for that increment.

6. The Energy Conservation Opportunities to be analyzed in this study are listed below:

a. Increment A - Area B Cogeneration: Investigate the feasibility of installing a nominal 150,000 pph topping turbine and generator for Area B. The normal operating load for the Area B steam plant varies from 150,000 to 200,000 pph; the full capacity of the plant is 400,000 pph. Steam is distributed at 300 psig and 525F. All but three users reduce the pressure to 100 psig. During mobilization, 300 psig is required for the plantwide distribution system; but a lower pressure (120 to 150 psig) could be used during normal operation. Adjustment and/or replacement of existing pressure reducing stations and traps would have to be included in the analysis. A new turbine and generator could accept steam at 300 psig, exhaust it to the distribution system at 150 psig, and generate a significant portion of the electricity required by Area B. Also required would be a new building to house the turbine and generator, electrical switchgear, a 300 psig takeoff upstream of the turbine for the users that require it, and a line to bypass 300 psig steam around the turbine during mobilization. Holston Defense Corporation has previously studied cogeneration at Area B, but the details differed from those of the current proposal. The AE will be provided a copy of the report, E88-0007, for his information.

b. Increment B - Area B Vacuum Pump: Study the technical and economic feasibility of replacing the existing steam jet on the bag house of the ash-handling system at Area B with a vacuum pump.

c. Increment C - Area B Intermediate Steam Pressure Header: Investigate the technical and economic feasibility of increasing the exhaust pressure of the existing turbine drives for each boiler and using the exhaust steam to heat feedwater. Each boiler uses a Skinner single-stage turbine to drive a forced-draft and an induced-draft fan on a common shaft. The inlet pressure is 300 psig, and the exhaust pressure is approximately 5 psig. It is proposed to raise the exhaust pressure to a level to be determined by the study (50 psig has been suggested), and to use the exhaust steam to increase the feedwater temperature to the economizer.

d. Increment D - Area B Air Preheaters: Investigate the technical and economic feasibility of installing tubular air preheaters on the four Area B boilers downstream of the existing economizers. It is believed that the temperature of the flue gasses leaving the economizer currently are on the order of 500F (measurements would have to be made to verify the actual temperature at different loads). The minimum permissible temperature entering the electrostatic precipitator is 280F. Therefore there is a possible temperature differential of 220F which could be utilized to increase the temperature of the under-fire combustion air.

e. Increment E - Area B Boiler Plant Modifications: Study the technical and economic feasibility of the following:

1) Blowdown Heat Exchanger: Install a heat exchanger to recover heat from the continuous blowdown.

2) Condensate Collection: Due to possible explosives contamination, no condensate is returned from Area B to the boiler plant. However, not even the condensate produced in the boiler plant is returned. Install a condensate return system for the boiler plant only.

3) Instrumentation and Operations: Determine the savings that could be achieved by the installation, repair, or replacement of simple instruments such as thermometers, pressure gages, and draft gages. Also consider the initiation of a boiler plant data sheet.

f) Increment F - Area A Vacuum Pump: Investigate the technical and economic feasibility of replacing the existing steam jet on the bag house of the ash-handling system at Area A with a vacuum pump. 7

g) Increment G - Area A Pumps: Many of the electrically operated pumps at the Area A boiler plant are sized for mobilization capacity, but they normally operate at a much lower capacity. 8 Investigate the technical and economic feasibilty of installing small auxiliary pumps to bypass larger pumps during normal operation.

h) Increment H - Area A Cooling Water: Filtered river water is used for cooling stokers and other equipment at the Area A steam plant. Although this water is not contaminated by the cooling process, it is currently piped to the industrial waste sump and then pumped approximately five miles to the industrial waste treatment plant. Investigate the technical and economic feasibility of rerouting this cooling water to the storm sewer.

i) Increment I - Area A Preheater: At the Area A steam plant, excess 5# steam is periodically vented to atmosphere. Investigate the technical and economic feasibility of using this steam to preheat combustion air.

j) Increment J - Area A & Area B Common ECOs: Investigate the following energy conservation opportunities for both Area A and Area B:

1) Inlet Air Dampers: Install manually-controlled inlet air dampers in the roof openings over the boilers. These dampers would be used to restrict the openings in the winter so that the warmer air from the upper level of the boiler plant would be pulled down by the forced draft fans. They would have to be left open for ventilation during the summer.

2) <u>Coal Feed Rate Monitoring:</u> Currently there is no accurate way to determine the heat rate (lb steam produced per lb coal fired) for an individual boiler. The existing coal handling system includes a belt scale which, at best, can provide a rough estimate of the quantity of coal delivered to the plant. Investigate the technical and economic feasibility of installing coal feed rate measuring devices on the chutes feeding the stokers or on the stokers themselves (each boiler is fed by six stokers). The signals from these devices would be integrated with the signal from the steam flow meter to provide the desired output.

7. Government-furnished information. The following documents will be furnished to the AE:

a. Holston Defense Corporation Engineering Report ER88-0007, dated 11 July 1988, subject: Cogeneration of Steam and Electricity at HSAAP Using No. 5 Boiler, Bldg 200, Area B.

b. U. S. Army Corps of Engineers, Architectural and Engineering Instructions - Design Criteria, 14 July 1989.

c. Energy Conservation Investment Program (ECIP) Guidance, dated 25 April 1988 and revision dated 15 June 1989.

d. TM5-785, Engineering Weather Data (applicable portions).

e. TM5-800-2, Cost Estimates, Military Construction.

f. AR 5-4, Change 1, Department of the Army Productivity Improvement Program.

g. AR 420-49, Heating, Energy Selection and Fuel Storage, Distribution, and Dispensing Systems.

h. Tri-Service Military Construction Program (MCP) Index, dated <u>28 February 1991</u>.

8. A computer program titled Life Cycle Costing in Design (LCCID) is available from the BLAST Support Office in Urbana, Illinois for a nominal fee. This computer program can be used for performing the economic calculations for ECIP and non-ECIP ECOs. The AE is encouraged to obtain and use this computer program. The BLAST Support Office can be contacted at 144 Mechanical Engineering Building, 1206 West Green Street, Urbana, Illinois 61801. The telephone number is (217) 333-3977 or (800) 842-5278. <u>Latest revision is Level 62. AE advised to use this version.</u>

9. Direct Distribution of Submittals. The AE shall make direct distribution of correspondence, minutes, report submittals, and responses to comments as indicated by the following schedule:

AGENCY	EXECUTIVE SUMMARIES	REPORTS	FIELD NOTES	CORRESPONDENCE
Commander Holston Army Ammunition Plant ATTN: SMCHO-EN (Mr Shelton) Kingsport, TN 37660-9982	3	3	1**	-
Commander U S AMC Installation and Service Activity ATTN: AMXEN-B (Mr Badtram) Rock Island, IL, 61299 - 7190	1	1	-	-
Commander U. S. Army Corps of Engineers ATTN: CEMP - ET (Mr Torabi) 20 Massachusetts Avenue NW Washington, DC, 20314 - 1000	1*	-	-	-
Commander USAED, South Atlantic ATTN: CESAD-EN-TE (Mr Baggette) 77 Forsyth Street, SW Atlanta, GA 30335 - 6801	1	1	-	-
Commander USAED, Mobile ATTN: CESAM-EN-CC (Battaglia) PO Box 2288 Mobile, AL 36628-0001	2	2	1**	2
Commander U. S. Army Logistics Evaluation Agency ATTN: LOEA-PL (Mr Keath) New Cumberland Army Depot New Cumberland, PA, 17070 - 5007	1*	-	-	-

* Receives final report only.
** Field Notes submitted in final form at interim submittal.

ANNEX B

EXECUTIVE SUMMARY GUIDELINE

1. Introduction.

2. Building Data (types, number of similar buildings, sizes, etc.)

3. Present Energy Consumption of Buildings or Systems Studied.

   - o Total Annual Energy Used.

   - o Source Energy Consumption.

     Electricity - KWH, Dollars, BTU
     Fuel Oil - GALS, Dollars, BTU
     Natural Gas - THERMS, Dollars, BTU
     Propane - GALS, Dollars, BTU
     Other - QTY, Dollars, BTU

4. Energy Conservation Analysis.

   - o ECOs Investigated. *

   - o ECOs Recommended. *

   - o ECOs Rejected. (Provide economics or reasons)

   - o Operational or Policy Change Recommendations.

* Include the following data from the life cycle cost analysis summary sheet: the cost (construction plus SIOH), the annual energy savings (type and amount), the annual dollar savings, the SIR, the simple payback period and the analysis date.

5. Energy and Cost Savings.

   - o Total Potential Energy and Cost Savings.

   - o Percentage of Energy Conserved.

   - o Energy Use and Cost Before and After the Energy Conservation Opportunities are Implemented.

CONFIRMATION NOTICE

Confirmation No. 1 EMC #3102.001

DATE:	5 August 1991
PROJECT:	LIMITED ENERGY STUDY HOLSTON ARMY AMMUNITION PLANT
CONTRACT NO.	DACA01-91-D-0032
NOTES PREPARED BY:	Carl E. Lundstrom E M C Engineers, Inc.
DATE OF CONFERENCE:	30 July 1991
PLACE OF CONFERENCE:	Holston Army Ammunition Plant (HSAAP) Main Administration Building
SUBJECT:	To discuss the requirements of the Scope of Work, provide clarification, and develop delivery orders for IDT contract.
ATTENDEES:	Anthony W. Battaglia, Corps of Engineers, Mobile, (205) 690-2618 Dennis Jones, E M C Engineers, Inc., (303) 988-2951 Carl E. Lundstrom, E M C Engineers, Inc., (404) 952-3697 Scott Shelton, SMCHO-EN, (615) 247-9111 x 3791 Willard Williams, Resident Engineer, Mobile, (615) 247-9111 x 3850 Jerry Bouchillon, Holston Defense Corp., (615) 247-9111 x 3471

The following is a summary of the items discussed, the comments made, and the decisions made during the Conference:

1. Mr. Battaglia provided EMC with the following documents in regard to the project:

    - NISTIR 85-3273-5, Energy Prices and Discount Factors
    - Holston Defense Corporation Engineering Report, ER88-0007
    - TM5-785, Weather Data
    - AR5-4, Change 1, Productivity Improvement Program
    - AR420-49, Heating, Energy Selection and Fuel Storage, Distribution, and Dispensing Systems

- MCP Index, 28 Feb. 91
- ECIP Guidance, 28 June 1991
- Architectural and Engineering Instructions, 14 July 1989

2. Mr. Lundstrom agreed to check EMC's office materials to see if they had copies of:

   - TM5–800–2, Cost Estimates Military Construction, June 1985

3. Mr. Battaglia explained using the latest version of LCCID Version 62 program would be required. He recommended EMC contact the Blast support office for the program.

4. Mr. Battaglia made some comments regarding the general scope of the project:

5. Mr. Bouchillon, Holston Defense Corp.(HDC), made the following comment regarding the issue and concerns of HSAAP:

   - There are restrictions at HSAAP; no cameras, radios, glass, and especially no matches.
   - If EMC wants pictures or videos, the facility photographer can take photos or videos.
   - HSAAP must have two weeks' prior notice for site visits, to get persons into their security system.
   - EMC should bring a list of test equipment to the safety briefing for approval.
   - EMC needs to coordinate the site visit with Bob Bausell, Area B, and Roy Wood, Area A.
   - The engineers working for EMC must have a safety briefing before working in the plant restricted areas.
   - The engineers working for EMC must have a security badge at all times.
   - An HDC or government employee must escort the engineers working for EMC at all times, for security and safety reasons.

6. Questions regarding the general Scope of Work, dated December 1990, were discussed:

6.1 Paragraph 2.3:

Question: Please review the intent of this paragraph, regarding:
– All methods of energy conservation.
– O & M improvements.

Answer: If EMC identifies an improvement, EMC can pursue these as they deem reasonable, but the Government will not require EMC to

evaluate more than the ECOs identified in the Scope of Work.

6.2 Paragraph 2.4:

Question: Please review the intent of this paragraph, regarding:
- Energy sources.
- Building, system, and ECO.

Answer: EMC is not to consider alternative fuels as a possible ECO.

6.3 Paragraph 3.7 Interviews:

Question: Would you like EMC to conduct entry and exit interviews for each increment – delivery order?

Answer: EMC should have an entry and exit interview every time they're at the plant for a survey. EMC should expect the facility commander to be included in the briefing.

6.4 Paragraph 6.2 Survey:

Question: Are there specific tests or measurements the Government wants performed?

Answer: EMC should take whatever tests are necessary to support the analysis. There are no special tests the Government would request or require specifically.

6.5 Paragraph 6.4 Presentations:

Question: Please review the paragraph sections regarding presentations. Is it intended there be a presentation at the interim stage for each delivery order? Is there any presentation after the final submittal?

Answer: There should be a presentation at the interim stage for each delivery order. No presentations are required at the final submittals.

6. General:

Question: There is no synergistic analysis of combinations of ECOs evaluated. Is there a plan to make an increment for looking at the combinations of individually recommended ECOs?

Answer: No.

Question: Please review the level of detail required, and types of items to be addressed in the "Operational or Policy Change Recommendations" (see Annex B).

Answer: EMC should include brief description of operational recommendations, but is not required to produce SOPs, diagrams or drawings, or perform analysis.

7. Questions regarding the Annex A portion of the Scope of Work, dated December 1990, were discussed:

7.1 Annex A, increment A.:

Question: How does this study differ from the previous study?
Answer: The other study included renovation of existing boilers and other special considerations.

Question: What utility restrictions or incentives are there for this project?
Answer: EMC needs to investigate this with the utility.

Question: Does the Army want to sell excess power to the utility, or can the Army consume all power produced?
Answer: It is believed the Army will consume all the power.

7.2 Annex A, increment B.:

Question: Is there an operational problem with the existing jet?
Answer: No, it is a big energy waste. HSAAP has converted many of the existing steam jet vacuum systems to vacuum pumps in other buildings.

7.3 Annex A, increment C.:

No questions. The general concept of the project was discussed.

7.4 Annex A, increment D.:

No questions. The general concept of the project was discussed. Locations, ducting, and temperatures will be looked at carefully.

7.5 Annex A, increment E.:

Question: Is blowdown automatic or manual?
Answer: Manual, continuous.

Question: What type controls do they have?
Answer: Area B plant has original 1940's vintage controls. Area A plant has new oxygen trim controls.

7.6 Annex A, increment F.:

See item 7.2, Annex A, increment B.

7.7 Annex A, increment G.

No questions. The general concept of the project was discussed.

7.8 Annex A, increment H.:

Comment by Mr. Lundstrom:

To properly evaluate the technical feasibility of this ECO will involve environmental evaluation of such items as allowable water temperature discharge, ground water, surface drainage, permitting by NPDES, and so forth. The environmental evaluation could be significant cost.

Answer by Mr. Battaglia:

It was agreed the environmental issues must be addressed.

7.9 Annex A, increment I.:

No questions. The general concept of the project was discussed.

7.10 Annex A, increment J.:

No questions. The general concept of the project was discussed.

8. The formal meeting at HSAAP administration offices was completed by 11:30 a.m. In the afternoon the group visited with Bob Bausell regarding ECOs related to Area B boiler plant. The group then visited the Area B boiler plant.

While in the plant, Mr. Lundstrom brought up the question of locations to take readings (temperatures, stack emissions, and so forth) with Mr. Battaglia and Mr. Bausell. Mr. Lundstrom asked if there were existing holes or test ports to use. Mr. Lundstrom expressed his concern that if he had to drill new holes there may be asbestos, and EMC did not want to have to be concerned with asbestos removal. It was agreed EMC would not have to accomplish any asbestos removal for this project.

9. After the plant tour, the group went through the ECO increments and grouped them in the following order for evaluation:

No. 1 – Increments B and F

No. 2 – Increment A
No. 3 – Increments C, D, E1, and E2
No. 4 – Increments G, I, and J1
No. 5 – Increment H
No. 6 – Increments E3 and J2.

It was agreed that Increments C, D, E1, and E2 are strongly interrelated and should be analyzed as a group.

Carl E. Lundstrom, P.E.
E M C Engineers, Inc.
Remote Office Manager, Atlanta

CONFIRMATION NOTICE

Confirmation No. 2 EMC #3102.002 and .003

DATE: 27 SEPTEMBER 1991
To: Anthony Battaglia
Mobile District, Corps of Engineers
(205) 690–2618

PROJECT: LIMITED ENERGY STUDY
HOLSTON ARMY AMMUNITION PLANT

CONTRACT NO. DACA01–91–D–0032
Delivery Order 0002 and 0003

NOTES PREPARED BY: Carl E. Lundstrom
E M C Engineers, Inc.

SUBJECT: To discuss the requirements of the Scope of Work and provide clarification for IDT contract.

The following is a summary of the items discussed, the comments made, and the decisions made during the telephone conversation on 26 September 1991 between Anthony W. Battaglia, Corps of Engineers, Mobile, and Carl E. Lundstrom, E M C Engineers, Inc.

1. Mr. Lundstrom asked if the submittal date for the Interim Submittal for Delivery Orders 2 and 3, could be 31 January 1991. Mr. Battaglia thought that was a satisfactory date for the Interim Submittal.

2. Mr. Lundstrom asked if the submittals for Delivery Orders 2 and 3 could be prepared in one report to be provided to the government. Mr. Battaglia agreed this was a satisfactory approach.

3. Mr. Battaglia reminded Mr. Lundstrom about the review conference after the Interim Submittal for the cogeneration study. Mr. Lundstrom explained that EMC will present all the findings of the Interim Submittal at the review conference.

Carl E. Lundstrom, P.E.
Project Manager

If any portion of this confirmation notice is incorrect, please notify us immediately. If correspondence is not received to the contrary within 14 days, it will be assumed that the decisions and conclusions, and status outlined in this confirmation notice are correct.

CONFIRMATION NOTICE

Confirmation No. 3 EMC #3102.002

DATE: 14 October 1991

PROJECT: Limited Energy Studies - Holston Army Ammunition Plant

CONTRACT No: DACA01-91-D-0032
Delivery Orders 2 & 3

NOTICE
PREPARED BY: Dennis Jones

SUBJECT: Field Survey

The field survey for the limited energy studies was conducted from 7 through 11 October 1991 by Carl Lundstrom, Dennis Jones, and Jim Edwards of EMC Engineers, Inc.

The field survey went very smoothly. Carl Lundstrom and Dennis Jones had previously visited the site in July and were able to develop a detailed list of required data prior to this trip. Personnel were helpful in providing information and data. Plans and data on the plant are well organized and maintained in files and on microfilm in the engineering section at HAAP. Plans were obtained for the steam distribution system and for applicable parts of the central steam plants. Key people contacted included:

Scott Shelton - SMCHO-EN x3791
Jerry Bouchillon - Energy Cordinator x3471
Roy Wood - Chief of Area A Utilities x8812
O.B. Wigley - Area B Maintenance Supervisor x3529
Max Noe - Area A Maintenace Supervisor x8858
Shelby Jones - Senior Electrical Engineer x3483
Sonny Hall

The one area where data collection was difficult was process energy loads. This data is necessary to determine the adequacy of the steam distribution system to operate at lower steam pressure. HAAP lacks organized data on the energy usage for their chemical processes. We obtained data on theoretical energy usage for processes and the amount of material processed, and will use this information to estimate process energy demand and loads.

The Area-B central steam plant was extensively surveyed to obtain data for analysis of possible ECMs and cogeneration. Measurements were made of temperature at various points in the system and a flue gas analysis conducted. Boiler blowdown rate was also measured.

Operating production buildings in Area B were surveyed to determine required steam pressures and to obtain data on existing PRV valves. Production personnel provided an explanation of the processes. The cogeneration ECM is highly dependant on the ability of the production area to operate on lower pressure steam and the capacity of the existing PRVs and piping. Measurements were also made of heat loss from selected sizes of distribution piping.

The Area A central steam plant was surveyed to obtain data for analysis of possible ECMs. The Area A plant is well instrumented and operational readings were obtained from the existing instrumentation.

HAAP has a number of studies ranging back to 1942. They have loaned EMC copies of these studies and also a copy of their Facilities Appraisal Manual.

During the survey a number of potential ECMs for future studies were identified.

Dennis Jones/CER

Action Required: None

Copies to: Tony Battaglia
Scott Shelton
Jerry Bouchillon

If any portion of this confirmation notice is incorrect, please notify us immediately. If correspondence is not received to the contrary within 14 days, it will be assumed that the decisions and conclusions, and status outlined in this confirmation notice are correct.

CONFIRMATION NOTICE

Confirmation No.: 4

DATE: 24 June 1992 EMC #3102-002

PROJECT: Limited Energy Studies - Holston Army Ammunition Plant

CONTRACT No.: DACA01-91-D-0032
Delivery Orders 2 & 3

NOTICE PREPARED BY: Dennis Jones
E M C Engineers, Inc.

SUBJECT: Review Conference for the Interim Submittal

ATTENDEES: Scott Shelton, SMCHO-EN, 615-247-9111, x3791
Jerry Bouchillon, HDC Engineering, 615-247-9111
Anthony W. Battaglia, COE Mobile, 205-690-2618
Dennis Jones, E M C Engineers, Inc., 303-988-2951

The following is a summary of the review comments and the resolution to those comments.

Jerry Bouchillon, Energy Coordinator

Summary:

This was an excellent report. The conciseness of the presentation in a detailed, yet readable form is outstanding. Particularly valuable is the boiler simulation computer software which is used extensively. Assumptions are realistic and conservative.

Five of the eight Engineering Conservation Opportunities (ECOs) are being submitted to the Army as FY95 ECIP Proposals. They are essentially being submitted as presented in the Report. The other 3 ECOs do not fit ECIP funding guidelines or for some other reason are held back for other funding.

Technical Comments:

1. **Paragraph 5.3.2: How do you know or what is your documentation for "the required temperature for the precipitators to function properly is 280°F"?**

   The required temperature of 280°F was provided by Bob Bausel, the Area B Central Plant Manager. The location of the heat recovery coil will be changed. The heat recovery coil will be located downstream of the precipitators to prevent any problem with precipitator operation. The report will be modified to reflect this change. EMC will use the chemical analysis of the coal to determine the temperature at which sulpheric acid will condense out of the flue gas. If it differs from the 280°F temperature, the report will be modified appropriately.

pages A-10, A-11, Detailed Scope of Work, e.g., it appears the following scopes of work were not studies: Area B Boiler Plant Instrumentation and Operations, Area A Cooling Water, Area A & B, Coal Feed Rate Monitoring. Were these an oversight or a scheduled deletion from the LES?

The ECOs mentioned in the above comment were not included in this contract. These were a scheduled deletion from the Statement of Work.

No action required.

8. **Tab C, Page C-3 & C-4: The enthalpy change of 1028 BTU/lb is questioned. It was derived from the difference between the enthalpy of superheated vapor (1271 BTU/1bm 300 psig and 525°F) and presumably the enthalpy of saturated liquid at 230°F or 5 psig. It appears the Hr = 243 BTU/lbm is in error and should be 198 BTU/1bm. Request verification.**

The 230°F temperature in the spreadsheet is not correct. It should read 30 psig. 30 psig is the pressure at which liquid condensate is expelled from the process and space heating steam traps. The enthalpy change of 1,028 BTU/lb. is correct. This is the available heat between the superheated steam at 300 psig and 525°F and the liquid condensate expelled at 30 psig. The report will be corrected.

9. **Tab C, Pages C-98, C-101, and C-102: The annual maintenance costs indicated, Page C-98, do not appear to have been included in the cost analysis for Cogeneration - Option 1 and 2. Request verification.**

The life cycle costing was performed with the Life Cycle Cost in Design program, commonly called LCCID. LCCID does not print out or display directly, maintenance costs or electric demand savings. Annual maintenance costs and electric demand savings are lumped together into the annual recurring non-energy costs as printed out in the program. For Option 1, the annual demand savings was $92,682. The annual maintenance cost was $52,776. Subtracting the annual maintenance cost from the annual demand savings, the result is $39,906 which is what you see printed out in the program on Page C-101. EMC has verified that the annual maintenance costs have been included for both options 1 and 2.

LCCID is a very difficult program to use and also to check for errors. In fact, since this project, EMC has reprogrammed LCCID into a Lotus spreadsheet which prints out a form that looks the same as the LCCID program. The Lotus spreadsheet is much easier to use than the LCCID program. For this report EMC will add another line to the LCCID spreadsheet and separate and display both annual electrical demand savings and annual maintenance costs.

10. **Tab E, Page E-16: Annual maintenance costs appear to not have been included in the cost analysis for feedwater pre-heater. Request verification.**

Maintenance costs were not included for the feedwater preheater for two reasons: 1) The maintenance costs on a feedwater preheater is

minimal and is insignificant compared to the energy savings produced by the feedwater heater; and 2) maintenance procedures would be performed inhouse and there would likely be no increase cost to the government. Maintenance costs on a feedwater preheater would be about 16 hours a year. EMC will add these maintenance costs to the life cycle costing and also will add maintenance costs for the other ECOs for which maintenance costs were considered negligible.

L.P. Covert

11. **Paragraph 4.7.4.2: Suggest the use of bus duct in lieu of large conductors for the 100 Amp feeder.**

I believe the reviewer was talking about the 1000 Amp feeder. A bus duct is a viable option to the large conductors. We believe the costs would be about the same. This is something that the designer should look at when the system is designed. EMC will add a statement to the report that mentions that a bus duct may possibly be used in lieu of the large conductors.

Hulen Shaw

General: A very good study.

12. **Area B Cogeneration: A maintenance contract could be less expensive in lieu of hiring a full-time maintenance person.**

A maintenance contract for the cogeneration turbines would probably be less expensive than hiring a full-time maintenance person. We assumed a full-time maintenance person for two reasons: 1) We wanted to make sure this project had enough funding in the O&M area to keep the cogeneration system operating. The existing cogeneration system is not operational due to lack of O&M funding; and 2) we wanted to provide justification for adding another maintenance person. EMC feels that the installation could benefit from additional maintenance personnel. A maintenance contract will be mentioned in the report as an alternative to hiring a full-time maintenance person.

13. **Combustion Air Preheaters: The temperature at which sulfur in the flue gas parcipitates must be considered when lowering flue gas temperature.**

See comment 1.

A. Battaglia

14. **Table ES-3 and Table 6-2: The before and after figures for Annual Energy $ are not consistent with the annual energy cost shown in Table ES-1 on page ES-2.**

On Table ES-3, the annual energy dollar savings are incorrect. The correct number is $6,462,600. Table ES-1 does not include electric demand charges. That is the difference between Tables ES-1 and ES-3. EMC will add demand costs to Tables ES-1, ES-2, and ES-3.

On Table ES-1, rows will be added for demand costs under both Area A and Area B Electricity Costs. On Table ES-2, a column will be added for electric demand costs. On Table ES-3, a column will also be added for electric demand costs. The tables in Section 6 summary will be modified similarly. The above modifications should clear up the discrepancies and confusion with electric demand costs.

15. **Table 2-1, Unit Energy Costs: The asterisk in the lower right hand box of the table appears to be misplaced. Should apply to Area B steam, not to electrical energy cost.**

    The report will be corrected.

16. **Paragraph 3.1, last line: Correct spelling of "effect".**

    The report will be corrected.

17. **Section 3.2.2.1, Steam Production: Average steam production is stated; please also mention the peak production expected under current operating conditions and how that relates to the "design" values used in some of the calculations.**

    Peak steam production expected under current operating conditions for both areas A & B will be presented in this section.

18. **Page 3-5: In defining m_z be sure to specify that this is the <u>dry</u> mass of flue gas.**

    The report will be clarified to indicate that we are referring to the dry mass of flue gas.

19. **Section 3.2.2.5, Flue Humidity Loss: Water vapor from combustion of hydrogen in the coal is mentioned; but water vapor contributed by the combustion air should also be included.**

    The report will be clarified to indicate that humidity in the combustion air is also part of this calculation.

20. **Page 3-7: Flow schematic is incorrectly referenced as Fig 3-2 on page 3-5. Please correct.**

    The flow schematic should reference Figure 3-1 on page 3-1. The report will be corrected.

21. **Figure 4.1: The PRV shown in the Administration Area is labeled "PRV 400/100 PSI"; shouldn't that be 300/100 PSI?**

    The PRV at the Administration Area is mislabelled. It should read, "300/100 PSI". The report will be corrected.

22. **Section 4.3.1.2: Delete the word "million" after 77,027,000.**

    The word "million" should not be there. The report will be corrected.

23. **Section 4.3.1.3: When discussing space heating loads, the base temperature for the heating degree days should be noted.**

The base temperature for the heating degree days is 65°F. The text will be modified to include a reference to the base temperature.

24. **Page 4-5: Last definition: Space heat coefficient should have units of BTUH/°F.**

The space heating coefficient will be corrected to indicate the proper units.

25. **Figure 4-4: I would expect the piping heat loss to be greater in winter than in summer since the Delta-T would be greater, i.e., the dark band on the graph would be "skinnier" in June, July, and August than in December, January, and February. Please explain why it appears to be the same thickness throughout the year.**

The plots of piping heat loss was derived from the spreadsheet on Page C-5. Referring to Page C-5, notice that the distribution losses are slightly greater in the winter time due to colder ambient temperatures. Pipe heat loss is driven by the temperature difference between the steam in the pipe at 525°F and ambient temperatures. The difference between the steam temperature and ambient temperature varies from 490°F to 450°F. There is only a 10% variation in the heat loss between the warmest and coldest month. This 10% variation is in the graph, but it is difficult to see.

No action required.

26. **Page 4-6: Delete redundant word "generated" from the last sentence.**

The report will be corrected and the word "generated" will be deleted.

27. **Table 4-1: Correct errors in Electricity Energy Cost and Total Energy Cost.**

On Table 4-1, the Electricity Energy Cost is consistent with the Energy Cost in Table ES-1 and that is the correct figure. The coal energy cost is slightly different from the baseline model developed in Section 4.0 due to use of a degree day space heat model.

No action required.

28. **Section 4.6.4: In discussing steam that bypasses the turbine, it could be stated that the steam bypassing the turbine would be treated by a PRV and a desuperheater to match the condition of the steam leaving the turbine; and that this steam would still be superheated at the lower pressure, i.e., still dry.**

Section 4.6.4 will be expanded to more clearly explain the PRV and superheater and its effect on the steam delivered on the distribution system using the suggestions in the above comment.

29. **Page 4-18, 4-19, & 4-21: Resolve conflict regarding size of tie-in to existing boiler feedwater line. Figure 4-8 and Section 4.7.4.1 have it as a 1-inch line; but Figure 4-9 shows a 2-inch line.**

The correct size of the tie in to the existing boiler feedwater line is 1". Figure 4-9 will be corrected to indicate a 1" feedwater tie in.

30. **The last paragraph of Section 4.7.4.2 refers to Figure 4-8 on page 4-18; appears it should be Figure 4-10 on page 4-23.**

Report will be corrected.

31. **Page 4-24: Correct Option 1 Total Construction Cost should be $749,500.**

Referring to Page C-98, the repair costs on the existing turbine should be $5,000 rather than the $6,000 in the text. The result is a total construction cost of $748,500. Report will be corrected accordingly.

32. **Section 5.2, Area B Intermediate Pressure Steam Header: Please include a piping schematic of the recommended system in this section.**

A piping schematic of the recommended system will be added to the report. The piping schematic will be a modification of Figure 3-1 showing the position of the recommended system.

33. **Section 5.3, Area B Combustion Air Preheaters: Please include a discussion of the piping requirements for the run-around loop. The temperature of the water in the loop will be above the boiling point, equivalent to about 30 to 50 psig; so a relief valve would be required. Also include a piping schematic in Section 5.3.**

A discussion of the piping requirements for the run around loop will be added to the discussion. A piping schematic will also be added showing the piping and all the major components. A pressure release valve will be included to the schematic and also included in the cost estimate. The life cycle cost will be recomputed.

34. **Section 5.3.5, Life Cycle Cost Analysis: The annual electricity savings should be negative rather than zero due to operation of the pump in the run-around loop.**

Electricity costs for operation of the pump on the run around loop will be added to the life cycle cost analysis. Also, the section number 5.3.5 will be corrected. The new section number should be 5.3.6.

35. **Section 5.6.2: This section states that 300 psig steam is supplied to Area A steam jet orifice plate. Area A CHP produces 400 psig steam. Is the 400 psig steam reduced to 300 psig for this purpose? Please clarify.**

At Area A, 400 lb. steam is used directly for the steam jet orifice plate. The steam flow through the steam jet orifice plate was incorrectly assumed to be the same at Area A as it was at Area B.

The steam rate at Area A should be greater than Area B. EMC will recalculate the steam rate for Area A and correct the report and analysis accordingly.

36. **Page 5-15: 3rd paragraph, last line: Annual electric usage increase should be 97 MBTU rather than 194.**

Report will be corrected.

37. **Section 5.7, Area A Electric DA Pump: In the discussion of the new bypass pump, it is not clear if it would be sized for average current operating conditions. Please clarify.**

The pump is sized for peak current operating conditions. The report will be clarified to indicate this. The peak operating flow requirements will be stated.

38. **Appendix D: Correct spelling of "Areas" on title sheet.**

The report will be corrected.

39. **Page G-1: State reason for sizing heat exchanger for 1100 GPM makeup and 25 GPM blowdown, i.e., large enough to handle peak (mobilization) capacity?**

It makes more sense to size the heat exchanger for the peak current usage rather than mobilization. EMC will resize this heat exchanger and correct the analysis accordingly. The design will include a bypass for full mobilization operation.

40. **Page G-3: Why is there no data on the B&G submittal sheet?**

EMC will resize this heat exchanger and submit a submittal sheet with data on it and will include the correct data sheet in the final report.

Dennis Jones

Dennis Jones

If any portion of this confirmation notice is incorrect, please notify us immediately. If correspondence is not received to the contrary within 14 days, it will be assumed that the decisions and conclusions, and status outlined in this confirmation notice is correct.

DEJ/smn(12)

APPENDIX B

BASE ENERGY ANALYSIS

Historical Energy Use Data B-1
Energy Cost Development B-4
Area-B CHP Performance Calculations B-6
Area-A CHP Performance Calculations B-28
Current Peak Steam Use Calculations B-35

EMC ENGINEERS, INC.
PROJ. #______ PROJECT ____________
SHEET NO. __1__ OF ______
CALCULATED BY ______ DATE ________
CHECKED BY ______ DATE ________
SUBJECT ____________

TABULATION OF DATA PROVIDED BY HAAP

ACCOUNTING DEPARTMENT COAL USAGE DATA
UTILITIES DEPARTMENT COAL USAGE DATA

		ACCOUNTING COAL RECORDS						UTILITIES COAL RECORDS			
		AREA–B BITUMINUS (tons)	AREA–B ANTHRACITE (tons)	AREA–B TOTAL (tons)	AREA–B COST ($)	AREA–A BITUMINUS (tons)	AREA–A COST ($)	AREA–B BITUMINUS (tons)	AREA–B ANTHRACITE (tons)	AREA–B TOTAL (tons)	AREA–A BITUMINUS (tons)
Jan	89	6,808	0	6,808	238,544	3,899	136,622	6,808	0	6,808	3,899
Feb	89	6,516	0	6,516	230,292	3,722	131,530	6,516	0	6,516	3,722
Mar	89	6,319	0	6,319	223,487	3,207	113,682	6,793	0	6,793	3,524
Apr	89	4,859	0	4,859	167,965	2,860	98,883	5,785	0	5,785	3,481
May	89	6,174	0	6,174	213,276	4,012	138,595	6,174	0	6,174	4,012
Jun	89	5,512	0	5,512	191,507	3,803	132,120	5,512	0	5,512	3,814
Jul	89	3,709	0	3,709	128,822	2,401	83,384	6,377	0	6,377	4,180
Aug	89	4,840	831	5,671	164,775	3,398	115,702	5,048	831	5,879	3,537
Sep	89	4,476	1,040	5,516	152,882	3,179	108,571	4,480	1,040	5,520	3,180
Oct	89	5,304	1,405	6,709	177,473	3,483	119,082	5,189	1,405	6,594	3,482
Nov	89	5,623	3,240	8,863	190,703	4,368	137,961	5,623	1,620	7,243	4,067
Dec	89	8,091	545	8,636	274,156	4,292	145,417	8,091	545	8,636	4,291
Jan	90	5,847	1,635	7,482	196,266	4,140	138,970	5,847	1,635	7,482	4,139
Feb	90	5,374	1,485	6,859	181,644	3,176	107,343	5,375	1,485	6,860	3,176
Mar	90	5,923	850	6,773	204,193	3,647	125,728	5,545	923	6,468	3,646
Apr	90	4,752	1,615	6,367	166,905	3,362	118,092	5,052	1,615	6,667	3,562
May	90	3,453	1,560	5,013	123,686	2,792	100,016	4,276	1,560	5,836	3,341
Jun	90	4,584	1,665	6,249	167,468	3,884	141,893	4,542	1,665	6,207	3,855
Jul	90	3,722	1,305	5,027	136,113	2,751	100,613	3,722	1,305	5,027	2,751
Aug	90	4,485	530	5,015	165,109	3,827	140,887	4,485	530	5,015	3,826
Sep	90	4,496	550	5,046	167,279	3,884	144,508	4,496	550	5,046	3,883
Oct	90	5,139	645	5,784	189,340	3,538	130,332	5,140	645	5,785	3,537
Nov	90	5,796	855	6,651	216,778	3,746	140,102	5,796	825	6,621	3,745
Dec	90	6,405	208	6,613	244,354	4,334	165,326	6,182	790	6,972	4,185
Jan	91	6,851	685	7,536	265,583	4,467	173,152	6,851	685	7,536	5,503
Feb	91	5,830	660	6,490	221,372	3,608	137,006	5,830	660	6,490	4,550
Mar	91	6,838	689	7,527	260,875	3,798	144,884	6,838	775	7,613	4,573
Apr	91	6,488	700	7,188	247,989	3,886	148,518	6,488	700	7,188	4,585
May	91	5,322	440	5,762	203,977	4,040	154,833	5,322	725	6,047	4,975
Jun	91	4,470	230	4,700	171,562	3,074	117,972				
Jul	91	7,987	435	8,422	290,516	4,228	153,777				
Aug	91	4,740	1,180	5,920	176,759	4,035	150,461				
	89	68,231	7,061	75,292	2,353,882	42,624	1,461,549	72,396	5,441	77,837	45,189
	90	59,976	12,903	72,879	2,159,135	43,081	1,553,810	60,458	13,528	73,986	43,646
	AVG	64,104	9,982	74,086	2,256,509	42,853	1,507,680	66,427	9,485	75,912	44,418

TABULATION OF DATA PROVIDED BY HAAP

ACCOUNTING DEPARTMENT ELECTRICITY USAGE DATA
UTILITIES DEPARTMENT STEAM PRODUCTION DATA

		TOTAL ELECTRICITY		AREA-A ELECTRICITY		AREA-B ELECTRICITY		STEAM PRODUCTION	
		TOTAL DEMAND (KW)	TOTAL USAGE (1000KWH)	AREA-A USAGE (KWH)	AREA-A DEMAND (KW)	AREA-B USAGE (KWH)	AREA-B DEMAND (KW)	AREA-A STEAM (MMLBM)	AREA-B STEAM (MMLBM)
Jan	89	9,648	6,120	928,000	1,463	5,192,000	8,185	82.3	140.2
Feb	89	9,408	5,448	826,000	1,427	4,622,000	7,981	79.6	134.1
Mar	89	9,288	5,424	955,000	1,408	4,469,000	7,880	74.8	139.2
Apr	89	9,288	5,736	929,000	1,408	4,807,000	7,880	75.5	115.5
May	89	9,144	5,136	795,000	1,387	4,341,000	7,757	81.3	116.4
Jun	89	9,240	5,208	981,000	1,401	4,227,000	7,839	80.2	100.2
Jul	89	9,528	5,712	1,091,000	1,445	4,621,000	8,083	71.1	97.3
Aug	89	9,864	5,544	1,268,000	1,496	4,276,000	8,368	74.1	107.2
Sep	89	10,296	6,060	1,068,000	1,561	4,992,000	8,735	70.7	101.1
Oct	89	9,552	5,904	991,000	1,448	4,913,000	8,104	75.7	121.3
Nov	89	9,864	6,198	934,000	1,496	5,264,000	8,368	84.6	133.1
Dec	89	9,936	6,216	892,000	1,507	5,324,000	8,429	79.7	146.5
Jan	90	10,416	6,816	917,000	1,579	5,899,000	8,837	85.5	134.0
Feb	90	9,984	5,820	1,010,000	1,514	4,810,000	8,470	66.8	124.4
Mar	90	9,816	5,736	967,000	1,488	4,769,000	8,328	78.1	131.5
Apr	90	9,864	6,396	1,109,000	1,496	5,287,000	8,368	75.4	120.5
May	90	9,648	5,580	894,000	1,463	4,686,000	8,185	73.4	105.5
Jun	90	10,104	5,706	691,000	1,532	5,015,000	8,572	81.6	108.5
Jul	90	9,912	6,246	978,000	1,503	5,268,000	8,409	59.1	89.6
Aug	90	9,672	5,646	686,000	1,467	4,960,000	8,205	83.3	103.1
Sep	90	9,996	5,688	830,000	1,516	4,858,000	8,480	77.2	100.1
Oct	90	9,804	5,880	852,000	1,487	5,028,000	8,317	78.0	111.8
Nov	90	9,804	5,544	784,000	1,487	4,760,000	8,317	77.9	124.1
Dec	90	9,816	5,760	641,000	1,488	5,119,000	8,328	97.6	131.2
Jan	91	10,266	6,288	616,000	1,557	5,672,000	8,709	90.8	140.0
Feb	91	10,800	6,096	648,000	1,638	5,448,000	9,162	73.6	129.3
Mar	91	10,392	6,120	651,000	1,576	5,469,000	8,816	79.6	139.0
Apr	91	10,530	5,745	949,000	1,597	4,796,000	8,933	79.0	131.7
May	91	10,944	5,448	762,000	1,659	4,686,000	9,285	84.8	106.9
Jun	91								
Jul	91								
Aug	91								

89			11,658,000	1,454	57,048,000	8,134	929	1,452
90			10,359,000	1,502	60,459,000	8,401	934	1,384
AVG	0		11,008,500	1,478	58,753,500	8,268	932	1,418

EMC ENGINEERS, INC.
PROJ. #_____ PROJECT [illegible]
SHEET NO. 3 OF 35
CALCULATED BY [illegible] DATE [illegible]
CHECKED BY______ DATE______
SUBJECT [illegible]

DATA TABULATION EQUATIONS

EMC ENGINEERS, INC.
PROJ. #______ PROJECT ____________
SHEET NO. 3 OF 35
CALCULATED BY ______ DATE ______
CHECKED BY ______ DATE 1/13/92
SUBJECT ____________

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A:AC13: {LR} +$UA*($TSTM-Y13)*24*30/$DH/1000
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A:AE13: {LR} +$PROC
A:AF13: {LR} (,0) +AD13-$PROC
A:AG13: {LR} +$BLC*24*Z13/$DH/1000
A:AH13: {LR} (P1) (AF13-AG13)/AA13
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EMC ENGINEERS, INC.
PROJ. #_____ PROJECT _____
SHEET NO. 4 OF _____
CALCULATED BY _____ DATE _____
CHECKED BY _____ DATE _____
SUBJECT _____

ENERGY COSTS

ELECTRICITY

Demand $9.64/kW x 0.985 (Discount) = $9.50/kW

Usage ($0.01852 - $0.0024265 (Fuel Adjustment)) x 0.985 = $0.01585/kWh

Average 1990 $\dfrac{\$2{,}266{,}947}{70{,}818{,}000 \text{ kWh}} = \$0.0320/\text{kWh}$

Energy Cost $\dfrac{\$0.0320 \text{ kWh}}{0.003413 \text{ MMBtu}} = \$9.38/\text{MMBtu}$

COAL

Cost $35.20/ton (Price Obtained from Accounting Dept.)

14,100 Btu/lbm (Laboratory Analysis)

Energy Cost $\dfrac{\$35.20}{\text{Ton}} \; \dfrac{\text{lbm}}{0.014100 \text{ MMBtu}} \; \dfrac{\text{ton}}{2000 \text{ lbm}} = \$1.25/\text{MMBtu}$

STEAM

Area A

Avg.	Steam (1000 lbm)	Coal ($)	
89/90	932,000	$1,507,680	» $1.62/1000 lbm steam

Steam	400 psig, 575°F	h	=	1290 Btu/lbm
Condensate	5 psig liquid	h	=	196 Btu/lbm
		dh	=	1094 Btu/lbm

$\dfrac{\$1.62}{1000 \text{ lbm}} \; \dfrac{\text{lbm}}{1094 \text{ Btu}} \; \dfrac{10^6 \text{ Btu}}{\text{MBtu}} = \$1.48/\text{MBtu}$

Area B

Avg.	Steam (1000 lbm)	Coal ($)
89/90	1,418,200	$2,256,500

Bituminous	66,391 tons	86%	
Anthracite	9,485 tons	14%	(Assume Same Energy Content as Bituminous)
Total	75,876 tons		

If Anthracite were purchased, cost would be $\dfrac{75{,}876}{66{,}391}$ = 1.14 times the actual cost

$\dfrac{\$2{,}256{,}500 \times 1.14}{1{,}418{,}000 \; (1{,}000 \text{ lbm})} = \$1.82/1000 \text{ lbm steam}$

Steam	300 psig, 525°F	h	=	1270 Btu/lbm
Condensate	5 psig, 228°F	h	=	196 Btu/lbm
		dh	=	1075 Btu/lbm

$\dfrac{\$1.82}{1000 \text{ lbm}} \; \dfrac{\text{lbm}}{1075 \text{ Btu}} \; \dfrac{10^6 \text{ Btu}}{\text{MBtu}} = \$1.69/\text{MBtu}$

UTILITY BILL CALCULATION (ELECTRICITY)

THIS BILLING IS FOR september, 1991

BILLING DEMAND RATE IS $ 9.64
METERED KWH RATE IS $ .01852
SERVICE CHARGE IS $ 1192.00
DISCOUNT RATE IS $ .015

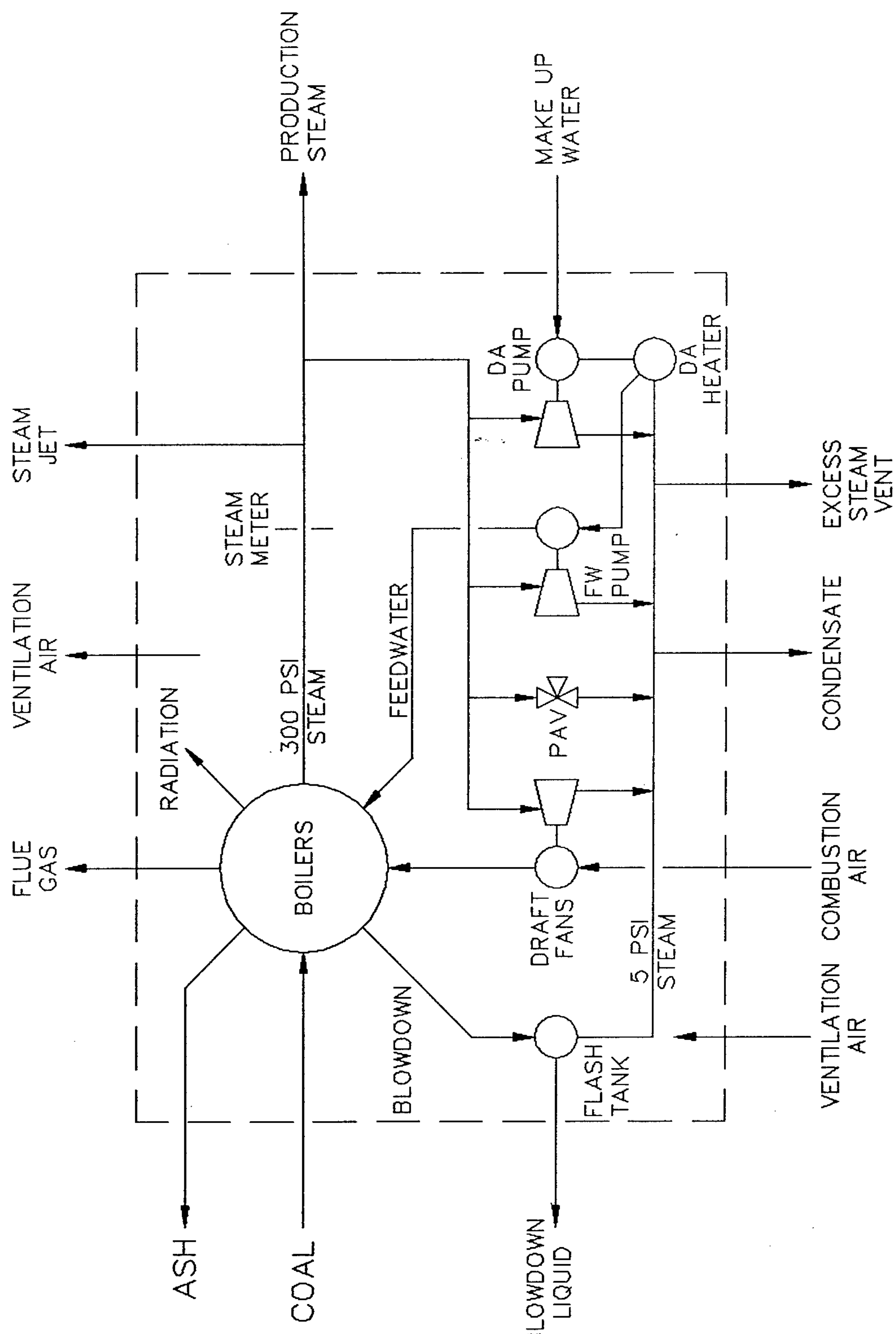
BILLING DEMAND IS 9816
METERED KWH IS 5904000
FUEL ADJUSTMENT RATE IS $ .0015966

BILLING DEMAND 9816 (X) 9.64	$ 94626.24
5904000 METERED KWH (X) .01852 =	109342.10
SERVICE CHARGE	1192.00
	$ 205160.30
FUEL ADJUSTMENT RATE .0015966 (X) %5904000.00 METERED KWH =	- 9426.33
TOTAL BEFORE DISCOUNT	$ 195734.00
DISCOUNT IS .015 (X) TOTAL	- 2936.01
THE TOTAL DUE IS	$ 192798.00

IF THIS RUN DOES NOT EQUAL THE INVOICE
PLEASE SEE BARBARA KISER.

EMC ENGINEERS, INC.
PROJ. # ____ PROJECT 3102-002
SHEET NO. 5 OF 35
CALCULATED BY [initials] DATE 11/15/91
CHECKED BY [initials] DATE 1/28/92
SUBJECT ____

EMC ENGINEERS, INC.
PROJ. #______ PROJECT 3102-002
SHEET NO. 6 OF 35
CALCULATED BY ____ DATE 11/15/9_
CHECKED BY ______ DATE ______
SUBJECT ______



EMC ENGINEERS, INC.
PROJ. # ______ PROJECT ______
SHEET NO. ______ OF ______
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AREA-B BASELINE COMPUTER BOILER MODEL

BOILERS5.WK3

HEATING VALUE OF COAL	HHV	14100.00	BTU/LBM	COAL ANALYSIS
THEORETICAL COMBUSTION AIR	THEO	11.00	LBM/LBM	LBH AIR/LBH COAL FROM ASHRAE FUNDAMENTALS
MIXED WATER TEMP	RETURN	56.00	F	LBH OF 5 PSI STEAM CONDENSED PER LBH OF MAKE UP
LATENT HEAT (5 PSI)	PSI5	960.00	BTU/LBM	STEAM TABLES
ECONOMOZER AIR TEMP IN	TEI	480	F	MEASURED
ECONOMIZER UA	ECON	25000.00	BTUH/F	AREA-A ECONOMIZER ANALYSIS
BLOWDOWN RATE	BLOW	2.46%	%	MEASURED
STEAM ENTHALPY	HS	1271.00	BTU/LBM	300 PSI, 626 F
LIQUID ENTHALPY	HL	399	BTU/LBM	300 PSI, SATURATED
LOW PRES STEAM ENTHALPY	HSLP	1,157	BTU/LBM	5 PSIG, SAT
DA HEATER LIQUID ENTHALPY	HLDA	196	BTU/LBM	228 F, SAT
AMBIENT TEMPERATURE	TA	56	F	WEATHER DATA
COMBUSTION LOSSES	LOSS	8.10%	%	ASSUMED
RADIATION LOSSES PER BOILER	RAD	1.65	MMBH	ASSUMED
DESIGN FAN HORSEPOWER	FANHP	550	HP	DESIGN DATA
DESIGN FAN CFM	FANCFM	52,500	CFM	DESIGN DATA
FAN STEAM RATE	FANSTM	21.60	LBH/HP	TURBINE MANUFACTURER
DA PUMP DESIGN HORSEPOWER	DAHP	80	HP	DESIGN DATA
DA PUMP DESIGN FLOW	DAGPM	1,750	GPM	DESIGN DATA
DA PUMP STEAM RATE	DASTM	54.8	LBH/HP	TURBINE MANUFACTURER
FW PUMP DESIGN HORSEPOWER	FWHP	135	HP	DESIGN DATA
FW PUMP DESIGN FLOW	FWGPM	460	GPM	DESIGN DATA
FW PUMP STEAM RATE	FWSTM	33.4	LBH/HP	TURBINE MANUFACTURER
BLOWDOWN FLASH STEAM	FLASH	21.10%	%	CALCULATED
FW PUMP HEAD	FWHEAD	700	FT	CALCULATED
VACUUM STEAM JET RATE	JET	932	LBH	CALCULATED
INTERMEDIATE HEADER PRESSUF	IHP	5	PSIG	
INTERMEDIATE HEADER TEMP	IHT	228	F	
PRE-HEATER EFFECTIVENESS	IHE	0.80		
PRE-HEATER LATENT HEAT	IHH	960	BTU.LBM	
LOW PRESSURE STEAM TEMP	LPT	228	F	

							BLOWDOWN HEAT RECOVERY			DEAERATING HEATER				DA PUMPS			FEEDWATER PUMP	
CONDITION	NUMBER OF DAYS	CHP STEAM DEMAND (LBM/HR)	CHP STEAM BALANCE (LBM/HR)	BOILER STEAM FLOW (LBM/HR)	BOILERS ON LINE	TOTAL FEED WATER (LBM/HR)	BLOW DOWN LIQUID (LBM/HR)	HEAT EXCHANGE EFF	HEAT TRANSFER (BTUH)	LEAVING MAKE UP TEMP (F)	5 PSI STEAM (LBM/HR)	MAKE UP WATER (LBM/HR)	LEAVING MAKE UP TEMP (F)	DA PUMP FLOW (GPM)	DA PUMP POWER (HP)	DA PUMP STEAM (LBM/HR)	FW PUMP FLOW (GPM)	FW PUMP POWER (HP)
BASECASE	30	135,200	(0)	161,891	2	165,873	3,142	0.00	0	56	25,203	140,670	228	282	36	2,472	333	84
DESIGN	30		539,432	640,000	4	655,744	12,422	0.00	0	56	99,636	556,108	228	1,117	67	3,826	1,317	333
JAN	31	172,191	0	205,045	2	210,089	3,980	0.00	0	56	31,922	178,167	228	358	40	2,616	422	107
FEB	28	166,877	(0)	198,751	2	203,640	3,858	0.00	0	56	30,942	172,698	228	347	36	2,472	409	103
MAR	31	151,466	(0)	180,498	2	184,938	3,503	0.00	0	56	28,100	156,838	228	315	36	2,472	371	94
APR	30	139,980	(0)	166,951	2	171,058	3,240	0.00	0	56	25,991	145,067	228	291	36	2,472	343	87
MAY	31	123,623	(0)	149,429	2	153,105	2,900	0.00	0	56	23,263	129,842	228	261	32	2,301	307	78
JUN	30	117,555	(0)	142,979	2	146,496	2,775	0.00	0	56	22,259	124,237	228	249	32	2,301	294	74
JUL	31	116,885	(0)	142,266	2	145,766	2,761	0.00	0	56	22,148	123,618	228	248	32	2,301	293	74
AUG	31	116,907	(0)	142,289	2	145,790	2,762	0.00	0	56	22,152	123,638	228	248	32	2,301	293	74
SEP	30	119,133	(0)	144,657	2	148,216	2,808	0.00	0	56	22,520	125,695	228	252	32	2,301	298	75
OCT	31	132,672	(0)	159,212	2	163,128	3,090	0.00	0	56	24,786	138,342	228	278	36	2,472	328	83
NOV	30	151,630	(0)	180,692	2	185,137	3,507	0.00	0	56	28,130	157,007	228	315	36	2,472	372	94
DEC	31	166,331	(0)	198,104	2	202,977	3,845	0.00	0	56	30,841	172,136	228	346	36	2,472	408	103

EMC ENGINEERS, INC.
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AREA-B BASELINE COMPUTER BOILER MODEL

BOILERS5.WK3 DA PUMP CURVE

GPM	HEAD	EFF	HP	PLR	%HP
0	218	0%	0	0%	0%
100	218	16%	34	5%	34%
200	218	27%	41	10%	41%
300	217	36%	46	15%	45%
400	217	44%	50	20%	50%
600	215	55%	59	30%	59%
800	214	63%	69	40%	68%
1,000	211	70%	76	50%	76%
1,200	209	75%	84	60%	84%
1,400	202	80%	89	70%	89%
1,600	193	84%	93	80%	92%
1,800	184	86%	97	90%	97%
2,000	173	87%	100	100%	100%
2,400	145	85%	103	120%	103%
2,800	90	74%	86	140%	86%

PART LOAD	STEAM OU	BLOWDOW	DRY FLUE	FLUE HUMI	RADIATION	COMBUSTION LOSS
BASECASE	72.52%	0.67%	13.44%	3.89%	1.38%	8.10%
DESIGN	77.12%	0.71%	9.43%	3.89%	0.74%	8.10%

CONDITION	FW PUMP STEAM (LBM/HR)	STEAM PRE-HEATER: HEAT TRANSFER (BTUH)	STEAM PRE-HEATER: STEAM DEMAND (LBM/HR)	LEAVING FW TEMP (F)	COMBUSTION AIR PREHEAER: HEAT EXCHANG EFF	COMBUSTION AIR PREHEAER: ENERGY EXCHANG (BTUH)	PRE HEAT EXIT (F)	FLUE GAS EXIT (F)	BOILER INCLUDING ECONOMIZER: STEAM OUT (LBM/HR)	BOILER FEED WATER (LBM/HR)	ESTMTD OXYGEN	PERCENT EXCESS AIR	COMBUST AIR FLOW (LBM/HR)	STEAM OUT (MBH)	FDW IN (MBH)	STEAM PRODUCE (MBH)	BLOW DOWN LOSS (MBH)	DRY FLUE LOSS (MBH)
BASECASE	3,149	(2)	(0)	228	0.00	0	56	386	80,945	82,937	10.60%	102%	188,181	103	16	87	1	16
DESIGN	9,787	0	0	228	0.00	0	56	398	160,000	163,936	5.33%	34%	232,093	203	32	171	2	21
JAN	3,748	(0)	(0)	228	0.00	0	56	391	102,522	105,044	9.16%	77%	204,715	130	21	110	1	18
FEB	3,661	0	0	228	0.00	0	56	390	99,375	101,820	9.37%	81%	202,603	126	20	106	1	18
MAR	3,408	0	0	228	0.00	0	56	388	90,249	92,469	9.98%	91%	195,938	115	18	97	1	17
APR	3,219	(3)	(0)	228	0.00	0	56	386	83,476	85,529	10.43%	99%	190,398	106	17	89	1	16
MAY	2,976	(9)	(0)	228	0.00	0	56	384	74,715	76,553	11.02%	110%	182,337	95	15	80	1	15
JUN	2,887	(9)	(0)	228	0.00	0	56	383	71,489	73,248	11.23%	115%	179,077	91	14	77	1	15
JUL	2,877	(9)	(0)	228	0.00	0	56	383	71,133	72,883	11.26%	116%	178,706	90	14	76	1	15
AUG	2,877	(9)	(0)	228	0.00	0	56	383	71,145	72,895	11.25%	115%	178,718	90	14	76	1	15
SEP	2,910	(9)	(0)	228	0.00	0	56	383	72,329	74,108	11.18%	114%	179,942	92	15	77	1	15
OCT	3,112	(8)	(0)	228	0.00	0	56	385	79,606	81,564	10.69%	104%	186,973	101	16	85	1	16
NOV	3,410	0	0	228	0.00	0	56	388	90,346	92,569	9.97%	90%	196,013	115	18	97	1	17
DEC	3,652	0	0	228	0.00	0	56	390	99,052	101,489	9.39%	81%	202,381	126	20	106	1	18

EMC ENGINEERS, INC.

PROJ. #______ PROJECT ______

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AREA-B BASELINE COMPUTER BOILER MODEL

BOILER5.WK3	DA PUMP	FW PUMP	DRAFT FAN	MISCELLAN	STEAM TO LOAD
	2,472	3,149	19,298	1,772	135,200

								ECONOMIZER					DRAFT FANS				CENTRAL HEATING PLA	
CONDITION	FUEL HUMIDITY LOSS (MBH)	RADIATION LOSS (MBH)	COMBUST LOSSES (MBH)	FUEL IN (MBH)	COAL FLOW (LBM/HR)	FLUE GAS FLOW (LBM/HR)	BOILER EFF	CAPACITY RATIO	NTU	EFF	EXIT AIR (F)	EXIT WATER (F)	FORCED DRAFT (SCFM)	INDUCED DRAFT (SCFM)	TOTAL HP	FAN STEAM (LBM/HR)	BLOW DOWN FLASH (LBM/HR)	TOTAL LO PRES STEAM (LBM/HR)
BASECASE	5	2	10	119	8,471	196,229	72.5%	0.57	0.53	0.37	386	283	41,818	43,606	421	9,649	840	25,759
DESIGN	9	2	18	222	15,746	247,052	77.1%	0.36	0.42	0.33	398	259	51,576	54,900	538	11,668	3,322	63,605
JAN	6	2	12	148	10,491	214,682	74.2%	0.49	0.49	0.36	391	273	45,492	47,707	462	10,361	1,064	28,151
FEB	6	2	12	144	10,199	212,292	74.0%	0.50	0.49	0.36	390	275	45,023	47,176	457	10,267	1,032	27,698
MAR	5	2	11	132	9,347	204,817	73.3%	0.53	0.51	0.36	388	278	43,542	45,515	440	9,976	937	26,768
APR	5	2	10	123	8,710	198,673	72.7%	0.56	0.52	0.37	386	282	42,311	44,150	426	9,741	867	26,039
MAY	4	2	9	111	7,880	189,824	72.0%	0.60	0.55	0.38	384	287	40,519	42,183	407	9,411	776	24,874
JUN	4	2	9	107	7,573	186,271	71.7%	0.61	0.56	0.38	383	289	39,795	41,393	400	9,281	742	24,492
JUL	4	2	9	106	7,539	185,867	71.6%	0.61	0.56	0.39	383	289	39,712	41,304	399	9,266	738	24,449
AUG	4	2	9	106	7,540	185,880	71.6%	0.61	0.56	0.38	383	289	39,715	41,307	399	9,267	739	24,450
SEP	4	2	9	108	7,653	187,212	71.7%	0.61	0.56	0.38	383	289	39,987	41,603	402	9,315	751	24,592
OCT	5	2	10	118	8,345	194,900	72.4%	0.57	0.53	0.38	385	284	41,549	43,311	418	9,599	826	25,608
NOV	5	2	11	132	9,356	204,902	73.3%	0.53	0.51	0.36	388	278	43,559	45,534	440	9,979	938	26,778
DEC	6	2	12	143	10,169	212,041	73.9%	0.50	0.49	0.36	390	275	44,974	47,120	456	10,257	1,028	27,666

EMC ENGINEERS, INC.
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AREA–B BASELINE COMPUTER BOILER MODEL

BOILERS5.WK3

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CONDITION		EXCESS LO PRES STEAM (LBM/HR)	EXCESS LO PRES VENT (LBM/HR)	PRV STEAM (LBM/HR)	TOTAL IN PLANT STEAM (LBM/HR)	TOTAL IN PLANT STEAM	STEAM TO LOAD (LBM/HR)	FUEL IN (MBH)	MONTHLY FUEL IN (MBH)	STEAM TO LOAD (MBH)	MAKE UP WATER (MBH)	CHP ENERGY ADDED (MBH)	CHP EFF	STEAM JET (MBH)	FLUE LOSS (MBH)	COMBUST LOSS (MBH)	EXCESS STEAM VENT (MBH)
BASECASE		555	555	0	26,691	16.49%	135,200	238.9	172,004	172	3	168	70.5%	1	41	19	0.642
DESIGN		(36,031)	0	36,031	100,568	15.71%	539,432	888.1	639,420	686	13	672	75.7%	1	118	72	0.000
	JAN	(3,770)	0	3,770	32,854	16.02%	172,191	295.9	220,114	219	4	215	72.5%	1	47	24	0.000
	FEB	(3,244)	0	3,244	31,874	16.04%	166,877	287.6	193,273	212	4	208	72.3%	1	46	23	0.000
	MAR	(1,333)	0	1,333	29,032	16.08%	151,466	263.6	196,108	193	4	189	71.6%	1	44	21	0.000
	APR	48	48	0	26,971	16.16%	139,980	245.6	176,856	178	3	174	71.0%	1	42	20	0.056
	MAY	1,611	1,611	0	25,806	17.27%	123,623	222.2	165,336	157	3	154	69.3%	1	40	18	1.864
	JUN	2,233	2,233	0	25,424	17.78%	117,555	213.5	153,755	149	3	146	68.6%	1	39	17	2.583
	JUL	2,301	2,301	0	25,381	17.84%	116,885	212.6	158,165	149	3	146	68.5%	1	38	17	2.662
	AUG	2,299	2,299	0	25,382	17.84%	116,907	212.6	158,189	149	3	146	68.5%	1	38	17	2.660
	SEP	2,072	2,072	0	25,524	17.64%	119,133	215.8	155,383	151	3	148	68.8%	1	39	17	2.397
	OCT	822	822	0	26,540	16.67%	132,672	235.3	175,079	169	3	165	70.2%	1	41	19	0.951
	NOV	(1,353)	0	1,353	29,062	16.08%	151,630	263.8	189,966	193	4	189	71.6%	1	44	21	0.000
	DEC	(3,175)	0	3,175	31,773	16.04%	166,331	286.8	213,349	211	4	207	72.3%	1	46	23	0.000
									2,155,572								

EMC ENGINEERS, INC.
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```
A:A38: {LRTB} [W15] 'BASECASE
A:B38: {Page LRTB} 30
A:C38: {LRTB} 135200
A:D38: {LRTB} +BI38-C38
A:E38: {LRTB} +C38+BG38
A:F38: {LRTB} 2
A:G38: {LRTB} +E38*(1+$BLOW)
A:H38: {LRTB} +E38*$BLOW*(1-$FLASH)
A:I38: {LRTB} (F2) 0
A:J38: {LRTB} +I38*H38*($LPT-$RETURN)
A:K38: {LRTB} +$RETURN+J38/M38
A:L38: {LRTB} +M38*(($LPT-K38)/$PSI5)
A:M38: {LRTB} +G38-L38
A:N38: {LRTB} (M38*K38+L38*$PSI5+L38*$LPT)/G38
A:O38: {LRTB} +M38/8.3/60
A:P38: {LRTB} (,0) @VLOOKUP(O38/$DAGPM,$PUMPHP,1)*$DAHP
A:Q38: {LRTB} +$DAHP*$DASTM*(0.8*P38/$DAHP+0.2)
A:R38: {LRTB} +G38/8.3/60
A:S38: {LRTB} (,0) +R38*$FWHEAD/3960/0.7
A:T38: {Page LRTB} +$FWHP*$FWSTM*(0.8*S38/$FWHP+0.2)
A:U38: {LRTB} @IF($IHE>0,@MIN($IHE*R38*500*($IHT-N38),BA38*F38*$IHH),0)
A:V38: {LRTB} +U38/$IHH
A:W38: {LRTB} (,0) +N38+U38/R38/500
A:X38: {LRTB} (F2) 0
A:Y38: {LRTB} +X38*(AV38-$TA)*AF38*0.24
A:Z38: {LRTB} +$TA+Y38/AF38/0.24
A:AA38: {LRTB} +AV38-Y38/AQ38/0.248
A:AB38: {LRTB} +E38/F38
A:AC38: {LRTB} +G38/F38
A:AD38: {LRTB} (P2) (16-AB38*66.7/1000000)/100
A:AE38: {LRTB} (P0) +AD38/(0.21-AD38)
A:AF38: {LRTB} +AP38*$THEO*(1+AE38)
A:AG38: {LRTB} +AB38*$HS/1000000
A:AH38: {LRTB} +AC38*(W38-32)/1000000
A:AI38: {LRTB} +AG38-AH38
A:AJ38: {LRTB} +$BLOW*AB38*$HL/1000000
A:AK38: {LRTB} 0.248*(AV38-Z38)*AQ38/1000000
A:AL38: {Page LRTB} +AP38*549/1000000
A:AM38: {LRTB} +$RAD
A:AN38: {LRTB} +$LOSS*AO38
A:AO38: {LRTB} +AG38-AH38+AJ38+AK38+AL38+AN38+AM38
A:AP38: {LRTB} +AO38*1000000/$HHV
A:AQ38: {LRTB} +AF38+0.95*AP38
A:AR38: {LRTB} (P1) (AG38-AH38)/AO38
A:AS38: {LRTB} (F2) +AQ38*0.24/AC38
A:AT38: {LRTB} (F2) +$ECON/AQ38/0.24
A:AU38: {LRTB} (F2) (1-@EXP(-AT38*(1-AS38)))/(1-AS38*@EXP(-AT38*(1-AS38)))
A:AV38: {LRTB} +$TEI-AU38*($TEI-W38)
A:AW38: {LRTB} +W38+AQ38*0.248*($TEI-AV38)/AC38
A:AX38: {LRTB} +AF38/0.075/60
A:AY38: {LRTB} +AQ38/0.075/60
A:AZ38: {LRTB} +$FANHP*(0.62*(AX38/$FANCFM)^2+0.04*AX38/$FANCFM+0.34)
A:BA38: {LRTB} +$FANSTM*$FANHP*(0.8*AZ38/$FANHP+0.2)
A:BB38: {LRTB} [W10] +E38*$BLOW*$FLASH
A:BC38: {LRTB} +Q38+T38+BA38*F38-V38+BB38
```

A:BD38: {Page LRTB} [W10] +BC38-L38

EMC ENGINEERS, INC.
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```
A:BE38: {LRTB} @IF(BD38>0,BD38,0)
A:BF38: {LRTB} @IF(BD38<0,-BD38,0)
A:BG38: {LRTB} +BC38+BF38+$JET
A:BH38: {LRTB} (P2) +BG38/E38
A:BI38: {LRTB} [W10] +AB38*F38-BG38
A:BJ38: {LRTB} (F1) +AO38*F38
A:BK38: {LRTB} +BJ38*B38*24
A:BL38: {LRTB} +BI38*$HS/1000000
A:BM38: {LRTB} +M38*($RETURN-32)/1000000
A:BN38: {LRTB} +BL38-BM38
A:BO38: {LRTB} (P1) (BL38-BM38)/BJ38
A:BP38: {LRTB} +$JET*$HS/1000000
A:BQ38: {LRTB} (AK38+AL38)*F38
A:BR38: {LRTB} +AN38*F38
A:BS38: {LRTB} (F3) +BE38*$HSLP/1000000
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EMC ENGINEERS, INC.
PROJ. #______ PROJECT ____________
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AREA-B BOILER PERFORMANCE

Steam Production:

Annual Steam Production = 1.418×10^9 lbm/yr from steam meters.

$$Average\ Hourly\ Steam\ Rate = \frac{1.418 \times 10^9}{8760} = 161{,}872\ lbm/hr.$$

Coal Consumption:

89/90 Average = 74,086 tons/yr from accounting data.

= 1.482×10^8 lbm/yr.

Evaporation rate = 1.418×10^9 / 1.482×10^8 = 9.57 lbm steam/lbm coal

$$Hourly\ Fuel\ Rate = \frac{1.482 \times 10^8\ lbm/yr \times 14{,}110\ Btu/lbm}{8760\ hrs/yr \times 10^6\ Btu/MBtu} = 239\ MBH.$$

Coal Energy Content:

Laboratory Analysis

Date	Btu/lbm
7/10/91	14,166
7/18/91	14,220
8/06/91	14,023
8/08/91	13,947
10/04/91	14,192

Average 14,110 Btu/lbm.

Yaura Wilkes   Ralph Smith

Branch Code 41 AUG 9 1991

Lab. No. 161694

Date Rec'd 8-6-91

Date Sampled ------

Sampled By Yourselves

STANDARD LABORATORIES INC.

EMC ENGINEERS, INC.
PROJ. # ______ PROJECT ______
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Holston Defense Corporation
West Stone Drive
Kingsport, TN 37660

ATTENTION: Ralph T. Smith

SAMPLE IDENTIFICATION

Sample # 25 - CPT - A
Contract No. 161000700200
Tons 2160.2
Coal Steam 2" X 0
Name of Contractor NA
Car Nos. and Initials SOU 360020,78293,75332,76980,76860, BLE 66061,
N&W 6890,144963,4205,11715,9277,93640,138767,168846,118194,14616,1450
9029,7642,69318,9023,9665,116375,92449, USAX 58005

	% Moisture	% Ash	% Volatile	% Fixed Carbon	B.T.U./LB.	% Sulfur
As Rec'd.	2.25	5.22	XXXX	XXXX	14023	0.73
Dry Basis	-----	5.34	XXXX	XXXX	14346	0.75
M-A-Free					15155	

NOTE: XXXX INDICATES ANALYSIS WAS NOT PERFORMED

Respectfully Submitted, Jimmy F. Watkins

Jimmy F. Watkins

COMBUSTION AIR ANALYSIS

The amount of combustion air supplied to the boilers varies with steam production. The following table summarizes data collected during the field survey:

Steam Rate (lbm/hr)	Oxygen in Flue Gas (%)	Flue Gas Temperature (°F)	Data Source
100,000	8.0	-	Conversation with Area-A operators
96,000	10.5	375	Measured at Area-B
42,300	13.5	378	Observed at Area-A
39,900	12.6	389	Observed at Area-A
30,000	14.0	-	Conversation with Area-A operators

Fitting a linear curve to the above data resulted in the following relation:

$$\% \; O_2 = 16 - 6.67 \times PLR \; ,$$

where PLR is the fraction of full capacity at which the boiler is operating.

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AREA-B IN-PLANT STEAM USE

Blowdown:

Controlled by manual valve set according to boiler water analysis. Boiler water at 300 psig is sent to the flash tank which is maintained at 5 psig.

Saturated liquid at 5 psig	h = 196 Btu/lbm
Saturated vapor at 5 psig	h = 960 Btu/lbm
Saturated liquid at 300 psig	h = 399 Btu/lbm

Energy released to steam is	= 399 - 196 = 203 Btu/lbm°F.
% flashed to steam	= 203/960 = 21.1%
or	
	100 - 21.1% = 78.9% remains liquid

Blowdown rate measurements:

56" ID tank rose 9" in 13.8 minutes

$$Tank\ Volume = \left(\frac{56}{12}\right)^2 x\ \frac{\pi}{4} x \frac{9}{12} = 12.8\ ft^3.$$

Saturated liquid specific volume @25 psig = 0.01715 ft^3/lbm.

$$Blowdown\ liquid\ mass\ flow = \frac{12.8 ft^3\ lbm\ x\ 60\ \text{min}/hr}{0.01715 ft^3\ x\ 78.9\%\ x\ 13.8\ \text{min}} = 4111\ lbm/hr.$$

During the test the boilers were producing 167,000 lbm/hr. The blowdown rate is 4111/167,000 = 2.46%.

Area-B Steam Jet

Steam jet operates 4 hr/day 75% of the time. Discharge is through (6) 5/16" orifices. A = 0.0767 in^2. Napiers equation is (marks 7th Edition, pp. 4-64):

$$m = \frac{Ap}{70},$$

where

- m = mass flow (lbm/sec),
- A = flow area (in^2), and
- p = pressure (psi).

Thus,

$$m = \frac{0.0767\ in^2 x\ 315\ lb/in^2}{70} = 0.345\ lbm/sec\ x\ 3600 = 1243\ lbm/hr\ .$$

6 holes = 7,455 lbm/hr.

<u>Area-A Steam Jet</u>:

$$m = \frac{0.0767\ in^2 x\ 415\ lb/in^2 x\ 3600}{70} = 1637\ lbm/hr\ ,$$

6 holes = 9822 lbm/hr.

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E   .INEERS, INC.
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COMMBUSTION ANALYSIS

ASHRAE 1989 Fundamentals, Chapter 5

Coal Composition:

5%	O
5%	H
81.4%	C
1.4%	N
0.7%	S
5.8%	Ash

Theoretical Air:

$$W_a = 0.0144 x (8C + 24H + 3S - 30) = 11.0 \; lbm\ air/lbm\ fuel.$$

Heat Loss in Water Vapor in Combustion Products:

$$9\ H_2\ x\ lbm\ Fuel\ (h_{hg} - h_{ft\ a})\ ,$$

where

H_2 = % hydrogen by weight,

h_{tg} = enthalpy of SH steam at flue gas temp to 1 psia, and

$h_{ft\text{-}a}$ = enthalpy of saturated H_2O at inlet air temperature.

$$9 \text{ x } 0.05(1242 - 22) = 549\ Btu/lbm\ Coal.$$

Heat Loss in Water Vapor in the Combustion Air:

$$m\ (h_{tg} - h_{g\ ta}) = 0.76\ Btu/lbm\ \ Coal,$$

where

m   54°F average DB; 50°F MC WB = 0.0067 lbm/lbm,

h_{tg} = 1199 Btu/lbm, and

h_{gta} = 1085 Btu/lbm.

Dry Flue Gas Loss:

$$q_2 = w_g\ C_{pg}\ (t_g - t_a)\ .$$

DEAERATING HEATER

Use of surface water from river, reservoir, and outdoor tank results in inlet water temperatures of 56°F which is average ambient temperature.

DA heater heats water to 228°F with 5 psig saturated steam which has latent heat of 960 Btu/lbm.

Mass balance is

$$\dot{m}_F = \dot{m}_M + \dot{m}_S ,$$

where

$\dot{m}_F$ = feedwater flow rate (lbm/hr),

$\dot{m}_M$ = makeup water flow rate (lbm/hr), and

$\dot{m}_S$ = steam flow rate (lbm/hr).

Energy balance is

$$\dot{m}_M t_m + \dot{m}_S (960 + t_s) + \dot{m}_F t_s ,$$

where

t_m = makeup water temperature (56°F), and

t_s = steam temperature (228°F).

Combining equations and solving:

$$\dot{m}_S + \frac{(\dot{m}_M (t_s - t_m)}{960} .$$

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FORCED AND INDUCED DRAFT FANS

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Turbine:

Skinner S-28-3
550 HP
300 psig in
525°F in
4200 rpm
Steam rate 21.6 lbh/HP

Boilers are designed for 160,000 lbh/hr.

$$Air\ Flow = \frac{160{,}000\ lbm/hr \times 10.3\ lbm\ Air \times 134\%}{9.35\ lbm\ Steam\ \ lbm\ Coal},$$

= 237,300 lbm/hr,

= 52,700 cfm.

Original Fan Curves (Design Flow = 160,000 lbh)

Forced draft	= 13.6" SP @ 53,000 cfm	175 hp
Induced draft	= 8.3" SP @ 53,000 cfm	120 hp
		295 hp

When new turbines were added along with precipitators, the induced draft resistance increased. The new turbines were sized at 550 hp.

$$Fan\ Power = P_F = P_{FD}\,F_F\,,$$

where

P_{FD} = 550 hp, and

F_F = fan characteristic (see figure on following page).

Steam Turbines:

Willan's line: Turbine part load performance is linear with turbines requiring 100% steam at 100% load and 60% steam at 50% load.

The following equation represents the Willian's line:

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$$F_T = 0.8 \times PLR + 0.2\ ,$$

where

F_T = fraction of full load steam, and

PLR = part load ratio.

1989 Fundamentals Handbook

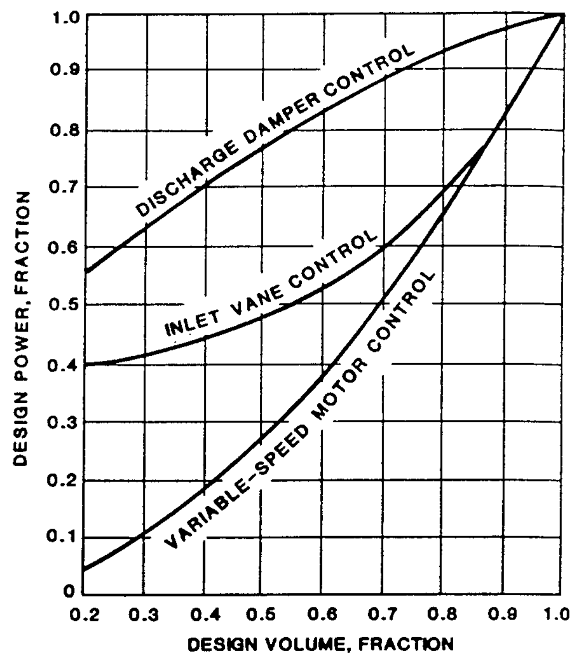

Fig. 7 Fan Power Versus Volume Characteristics

Fan Power

$$P_F = P_{FD}\, F_F\ .$$

where

P_F = power required by fans,

P_{FD} = power required by fans at full load, and

F_F = design power fraction.

Inlet vane control results in the following equation:

$$F_F = X^2 - 0.45X + 0.45,$$

where X is the fraction of design airflow.

Thus,

$$Steam\ Rate = 21.6\ lbh/hp\ [0.2 + 0.8 \times F_F] \times 550\ hp\ .$$

DH TURBINE DIVISION

FORM NO 0-211

Erie, Pennsylvania 16512

MECHANICAL DRIVE STEAM TURBINES

CUSTOMER NAME BECKMAN CONSTRUCTION CO.

ADDRESS P.O. DRAWER 12007, FORT WORTH, TEXAS 76

REQUISITION NO. ______ BECKMAN ORDER NO. 625-48-1

SIZE - RATING AND STEAM INFORMATION (See Note No. 6) CONTRACT NO. DACA0C-75-C-009

FRAME SIZE - NO. NOZZLES (See ~~DH-30200~~ 3-30800 for Dimensions)	5-28-3						
APPROXIMATE WEIGHT	2190						
LOAD RATING HP - MIN.	550						
INLET STEAM PRESSURE PSIG	300						
INLET STEAM TEMPERATURE F°	525°						
EXHAUST STEAM PRESSURE PSIG/~~or Vac. Inches Hg.~~	5						
RPM	42.00						
HAND VALVE "X"	OPEN						
HAND VALVE "Y"	OPEN						
ITEM NO. AREA "B" BOILER #1							
~~DEAN HILL~~ SECO SERIAL NO.	75 ST 10148						
MATERIAL CLASS	III						
ROTATION (From Governor End)	CCW						

SPECS. & DWGS. PER DACA0L-75-B-0046, REVISIONS THRU 0008

GENERAL INFORMATION

1. Flexibility must be provided in all connections to prevent transmission of excessive strains to turbine.
2. Minimum pipe sizes recommended for short, direct runs of pipe to steam connections are same size as the connections.
3. Dowel holes in turbine feet should be reamed and dowels fitted after final alignment.
4. ALL TURBINES MAY HAVE EXHAUST CONNECTION ON EITHER SIDE OF TURBINE. LOCATION MAY BE CHANGED BY INTERCHANGING BLIND FLANGE.
5. Connect shaft packing and valve stem leak-off drains to atmosphere, sewer on bilge without back-pressure on shut-off valve. They may be connected to a common line of not less than one-half (1/2) inch diameter for short, direct runs. Connect wheel casing and steam chest drains to sewer, bilge, open hot well or condenser, independent of all other piping, and with a shut-off valve in line.
6. Customer to check rating and steam information.
7. ~~Trico oiler furnished as standard equipment. Refer to Instruction Manual for oil level setting.~~

THE PURCHASER WILL PROVIDE THE FOLLOWING:

8. A rigid and substantial foundation, foundation bolts, nuts and shims.
9. All piping, valves, fittings, gaskets and flanges to connections shown, with all drain piping arranged to avoid formation of pockets or water legs.
10. Where turbine does not exhaust directly to atmosphere, install a relief valve adjusted to start relieving at not more than 75 PSIG and give full relief to 11880 pounds of steam per hour at not more than 85 PSIG. Valve must be installed between turbine and first shut-off valve in the exhaust line. STEAM RATE = 21.6 lb./HP.HR.

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Date 11-10-75 CERTIFIED for construction by [signature]

DA HEATER PUMP

Design conditions = 1750 gpm @ 185 ft H η = 86%.
(see curve on following page)

$$hp = \frac{1750 \, x \, 185}{3960 \, x \, 0.86} = 95 \, hp.$$

1750 gpm = 871,500 lbm/hr water (6 boilers).

DA pump conditions = 321 gpm @ 221 ft H η=36%.
Control is by throttling.

$$hp = \frac{321 \, x \, 221}{2960 \, x \, 0.36} = 50 \, hp.$$

Steam turbine steam rates follow a linear curve which passes through 60% steam rate at 50% part load. The resulting relationship is:

$$PLSR = SR(0.2 + 0.8 \; x \; PLR) \; ,$$

where

PLSR = part load steam rate,

SR = full load steam rate, and

PLR = part load ratio.

Calculation Procedure: (in boiler model)

(1) For a given flow rate.
(2) Pick pump efficiency from pump curve.
3) Calculate pump horsepower.
4) Calculate turbine steam demand from the following equation:

$$Steam \;\; Demand = 60.7 \; lbh/hp \, [0.2 + 0.8 \left(\frac{Pump \; hp}{80 \; hp} \right)] \, x \, 80 \, hp \, .$$

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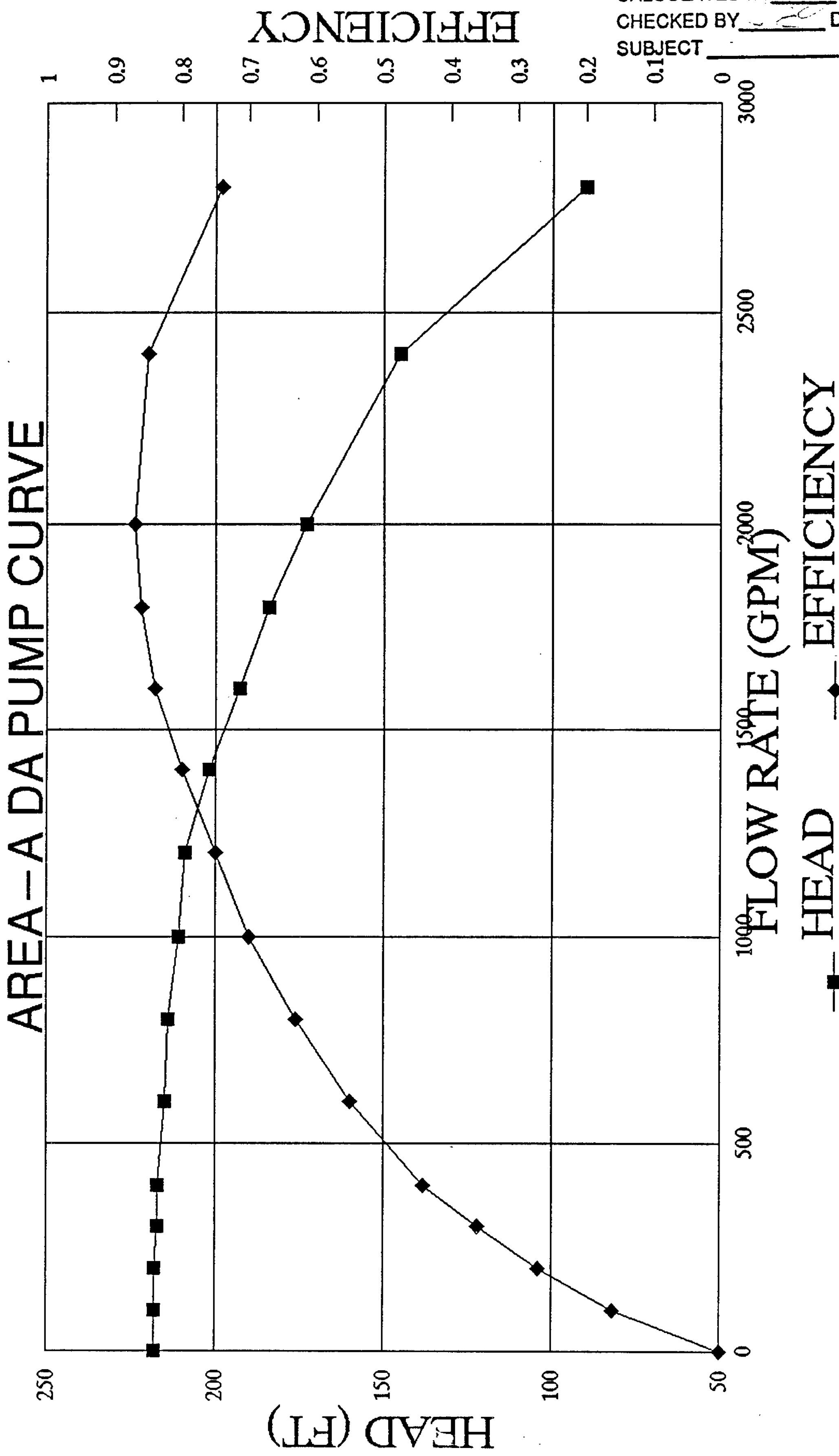

GE Industrial
& Power Systems

Navy & Small Steam Turbine
General Electric Company
166 Boulder Drive, Fitchburg, MA 01420
508 343-1000

EMC ENGINEERS, INC.
PROJ. #______ PROJECT ______
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SUBJECT ______

December 6, 1991

EMC Engineers
2750 South Wadsworth Blvd.
C-200
Denver, Colorado 80227-3493

Attn: Dennis Jones

Subject: Turbines S/N 123274 & 61592

Gentlemen:

Let me first apologize for having taken so long to get back to you. Retrieving the records on these units proved to be more of a task than first thought.

The following is the steam rate information for both turbines.

1. Turbine 123274 DA HEATER PUMP

 This machine is currently designed with steam conditions of 275PSIG - 525 F - 5PSIG/25PSIG with a load of 80HP at 1750RPM. The steam rate @ 5PSIG back pressure is 54.8 LB/HP HR and the steam rate @ 25 PSIG back pressure is 60.7 LB/HP HR.

 It is estimated that the steam rates @ 50PSIG back pressure would be 82 LB/HP HR with a load of 60HP at 1750 RPM and @75 PSIG back pressure the steam rate would be 121 LB/HP HR with a load of 40HP at 1750RPM.

2. Turbine 61592 FEEDWATER PUMPS

 This turbine is currently designed with steam conditions of 275PSIG - 470 F - 5PSIG/25PSIG with a load of 265HP at 3550RPM. The steam rates @ 5PSIG/25 PSIG back pressure are 35.5 LB/48 LB/HP HR respectively.

 It is estimated that the steam rates for this turbine @ 50PSIG back pressure 65 LB/HP HR with a load of 140HP at 3550RPM and @ 75PSIG exhaust pressure a steam rate of 102 LB/HP HR with a load of 90HP at 3550RPM.

Both machine <u>are</u> limited to 75PSIG exhaust pressure - however new nozzle plates and valves will be required.

If you have need of additional information relative to these units please contact this office at your convenience.

Robert S. Pridham
Robert S. Pridham

RSP/jh

FEEDWATER PUMPS

DA tank bottom:	1257 ft elev.
FW pumps:	1205 ft
Inlet press:	(1257 - 1205) + 5 psig x 2.3= 63.5 ft
Exit press:	300 psig x 2.3 = 690 ft
	= 527 ft

Design flow = 162,000 lbh / 8.3 lb / 60 min/hr = 325 gpm.

$$Pump\ hp = \frac{325\,x700}{3960\,x\,\eta} = 82\ hp.$$

$\eta = 0.70$.

Steam Turbine:

Turbine No.	Manufacturer	Model No.	Serial No.	Steam Rate (lbm/hr/hp)	Rated Horsepower (hp)
1-3	GE	DS-120	61592	35.5	265
4	Dresser Rand	DO-292	V24059	33.4	135

Turbine #4 is generally used since its horsepower more closely matches the load.

Calculation Procedure:

$$Pump\ hp = gpm\ x\ 700\ /\ 3960\ x\ 0.70.$$

$$Steam\ Use = 33.4\ lbh/hp\,x\left[0.2 + 0.8\left(\frac{Pump\ hp}{135\ hp}\right)\right]x\,135\ hp.$$

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CONDENSATE

Condensate Sources

Turbines:

Entering conditions: 300 psig, 525°F, h, = 1271 Btu/lbm.

$h_2 = h_1 - w,$
$w = 2545$ (Btu/hr/hp) / SR (lbm/hp/hr), where SR is steam rate,

$h_2 = 1271 - 2545 / SR,$

@ 5 psig ≈ 20 psia $h_f = 196$ and $h_g = 1156$

Quality (X):

$$X = \frac{h_2 - 196}{1156 - 196}.$$

Turbine	Avg. Steam Demand (lbm/hr)	Steam Rate (lbm/hr/hp)	h_2 (Btu/lbm)	X	Condensate Generated (lbm/hr)
Fans	19,426	21.6	1,153	0.991	175
DA pump	2,472	54.8	29	SH*	0
FW pump	3,149	33.4	1,195	SH*	0

*superheated

Superheated exhaust from pump turbines will offset pipe loss condensate generation. Remaining condensate is from fan turbines.

At 175 lbm/hr,

$$Q = 175\, lbm/hr \times (200 - 56)^\circ F \times 1\, Btu/lbm^\circ F = 25{,}176\, Btuh.$$

200°F = condensate temperature at make-up tank.

AREA-A CHP ANALYSIS

Area-A CHP is the same as Area-B except steam is generated at 400 psig to 575°F. The same turbines (i.e., DA pump, feedwater pump and fans) exhaust into 5 psig header which serves the DA heater.

Steam Energy Contents:

400 psig   575°F steam h_s=1291Btu/lbm h_f=248 Btu/lbm

Turbine Steam Rates:

	Area-B	Area-A
p_1	300 psig	400 psig
T_1	525°F	575°F
h_1	1271 Btu/lbm	1291 Btu/lbm
s_1	1.579 Btu/lbm/°F	1.570 Btu/lbm/°F
p_2	5 psig	5 psig
h_{2s}	1051 Btu/lbm	1045 Btu/lbm
TSR = $2545/h_1-h_{2s}$	11.6 lbm/hr/hp	10.3 lbm/hr/hp

At 400 psig the steam rate is 92% of the steam rate at 300 psig.

Steam Rates:

	Area-B (lbm/hr/hp)	Area-A (lbm/hr/hp)
Fans	21.6	19.2
DA pumps	54.8	0
FW pumps	33.4	30.8

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Blowdown Flash Steam

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400 psig water into 5 psig tank.

h_F = 428, saturated liquid at 400 psig,
h_F = 196, saturated liquid at 5 psig, and
h_g = 1156 saturated steam at 5 psig.

Percent flashed to steam = 24.2%:

$$428 = (1 - X) \times 196 + X \times 1156\ ,$$

$$X = 0.242\ .$$

Average Steam Flow:
(Average 89-90)

$$\frac{931{,}000{,}000\ lbm/yr}{8760} = 106{,}300\ lbm/hr\ .$$

Condensate Tank:

60% of condensate returned to plant.
Assume 180°F return temperature: 60%
56°F makeup water: 40%
Result: 130°F feedwater to DA heater

Feedwater Pump:
Head = 1000 ft.

DA Pump:
Electric - no steam.

Historical Coal Usage:

42,853 tons (avg. 89 and 90)

x 2000 = 85.7×10^6 lbm

@ 14,100 Btu/lbm = 1.208×10^6 MMBtu

÷ 8760 = 138.0 MBH average fuel rate, or 70.0 MBH per boiler.

Fly Ash (1990):

	Area-A	Area-B
Steam (lbm x 10^6)	934	1,384
Cinders (cy)	7,438	11,320
Fly ash (cy)	6,432	19,847
Evaporation rate (lbm steam/lbm coal)	10.7	9.3
Coal (tons)	43,658	72,879
Fly ash/ton coal (cy/ton)	0.147	0.272

Area-B produces about twice the fly ash of Area-A.

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AREA-A COMPUTER BOILER MODEL - BASELINE

BOILER-A.WK3

HEATING VALUE OF COAL	HHV	14100.00	BTU/LBM	COAL ANALYSIS
THEORETICAL COMBUSTION AIR	THEO	11.00	LBM/LBM	LBH AIR/LBH COAL FROM ASHRAE FUNDAMENTALS
MIXED WATER TEMP	RETURN	130.00	F	LBH OF 5 PSI STEAM CONDENSED PER LBH OF MAKE UP
LATENT HEAT (5 PSI)	PSI5	960.00	BTU/LBM	STEAM TABLES
ECONOMOZER AIR TEMP IN	TEI	480	F	MEASURED
ECONOMIZER UA	ECON	25000.00	BTUH/F	AREA-A ECONOMIZER ANALYSIS
BLOWDOWN RATE	BLOW	2.46%	%	MEASURED
STEAM ENTHALPY	HS	1291.00	BTU/LBM	300 PSI, 525 F
LIQUID ENTHALPY	HL	428	BTU/LBM	300 PSI, SATURATED
LOW PRES STEAM ENTHALPY	HSLP	1,157	BTU/LBM	5 PSIG, SAT
DA HEATER LIQUID ENTHALPY	HLDA	196	BTU/LBM	228 F, SAT
AMBIENT TEMPERATURE	TA	56	F	WEATHER DATA
COMBUSTION LOSSES	LOSS	0.00%	%	ASSUMED
RADIATION LOSSES PER BOILER	RAD	1.65	MBH	ASSUMED
DESIGN FAN HORSEPOWER	FANHP	550	HP	DESIGN DATA
DESIGN FAN CFM	FANCFM	52,500	CFM	DESIGN DATA
FAN STEAM RATE	FANSTM	19.20	LBM/HP/HR	TURBINE MANUFACTURER
DA PUMP DESIGN HORSEPOWER	DAHP	80	HP	DESIGN DATA
DA PUMP DESIGN FLOW	DAGPM	1,750	GPM	DESIGN DATA
DA PUMP STEAM RATE	DASTM	0.0	LBM/HP/HR	TURBINE MANUFACTURER
FW PUMP DESIGN HORSEPOWER	FWHP	135	HP	DESIGN DATA
FW PUMP DESIGN FLOW	FWGPM	460	GPM	DESIGN DATA
FW PUMP STEAM RATE	FWSTM	30.8	LBM/HP/HR	TURBINE MANUFACTURER
BLOWDOWN FLASH STEAM	FLASH	24.20%	%	CALCULATED
FW PUMP HEAD	FWHEAD	1,000	FT	CALCULATED
VACUUM STEAM JET RATE	JET	444	LBM/HR	CALCULATED
INTERMEDIATE HEADER PRESSUI	IHP	5	PSIG	
INTERMEDIATE HEADER TEMP	IHT	228	F	
PRE-HEATER EFFECTIVENESS	IHE	0.00		
PRE-HEATER LATENT HEAT	IHH	960	BTU/LBM	
LOW PRESSURE STEAM TEMP	LPT	228	F	

							BLOWDOWN HEAT RECOVERY			DEAERATING HEATER				DA PUMPS			FEEDWATER PUMP	
CONDITION	NUMBER OF DAYS	CHP STEAM DEMAND (LBM/HR)	CHP STEAM BALANCE (LBM/HR)	BOILER STEAM FLOW (LBM/HR)	BOILERS ON LINE	TOTAL FEED WATER (LBM/HR)	BLOW DOWN LIQUID (LBM/HR)	HEAT EXCHANG EFF	HEAT TRANSFER (BTUH)	LEAVING MAKE UP TEMP (F)	5 PSI STEAM (LBM/HR)	MAKE UP WATER (LBM/HR)	LEAVING MAKE UP TEMP (F)	DA PUMP FLOW (GPM)	DA PUMP POWER (HP)	DA PUMP STEAM (LBM/HR)	FW PUMP FLOW (GPM)	FW PUMP POWER (HP)
BASELINE	30	90,700	0	108,921	2	111,600	2,031	0.00	0	130	10,337	101,263	228	203	32	0	224	81
DESIGN	30		578,816	640,000	4	655,744	11,934	0.00	0	130	60,740	595,004	228	1,195	67	0	1,317	475

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AREA-A COMPUTER BOILER MODEL - BASELINE

BOILER-A.WK3 DA PUMP CURVE

GPM	HEAD	EFF	HP	PLR	%HP
0	218	0%	0	0%	0%
100	218	16%	34	5%	34%
200	218	27%	41	10%	41%
300	217	36%	46	15%	45%
400	217	44%	50	20%	50%
600	215	55%	59	30%	59%
800	214	63%	69	40%	68%
1,000	211	70%	76	50%	76%
1,200	209	75%	84	60%	84%
1,400	202	80%	89	70%	89%
1,600	193	84%	93	80%	92%
1,800	184	86%	97	90%	97%
2,000	173	87%	100	100%	100%
2,400	145	85%	103	120%	103%
2,800	90	74%	86	140%	86%

PART LOAD	STEAM OU	BLOWDOW	DRY FLUE L	FLUE HUMI	RADIATION	COMBUSTION LOSS
BASECASE	77.94%	0.75%	15.25%	3.89%	2.17%	0.00%
DESIGN	85.20%	0.82%	9.28%	3.89%	0.81%	0.00%

CONDITION	FW PUMP STEAM (LBM/HR)	STEAM PRE-HEATER: HEAT TRANSFER (BTUH)	STEAM PRE-HEATER: STEAM DEMAND (LBM/HR)	LEAVING FW TEMP (F)	STEAM AIR PREHEATER: HEAT EXCHANG EFF	STEAM AIR PREHEATER: ENERGY EXCHANG (BTUH)	PRE HEAT EXIT (F)	STEAM USAGE (LBM/HR)	BOILER INCLUDING ECONOMIZER: STEAM OUT (LBM/HR)	BOILER FEED WATER (LBM/HR)	ESTMTD OXYGEN	PERCENT EXCESS AIR	COMBUST AIR FLOW (LBM/HR)	STEAM OUT (MBH)	FDW IN (MBH)	STEAM PRODUCE (MBH)	BLOW DOWN LOSS (MBH)	DRY FLUE LOSS (MBH)
BASELINE	2,824	0	0	228	0.00	0	56	0	54,460	55,800	12.37%	143%	144,564	70	11	59	1	12
DESIGN	12,536	0	0	228	0.00	0	56	0	160,000	163,936	5.33%	34%	214,018	207	32	174	2	19

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AREA-A COMPUTER BOILER MODEL – BASELINE

BOILER-A.WK3	DA PUMP	FW PUMP	FANS	MISCELLAN	STEAM TO LOAD
	0	2,824	14,305	1,092	90,700

								ECONOMIZER					DRAFT FANS				CENTRAL HEATING PLA	
CONDITION	FUEL HUMIDITY LOSS (MBH	RADIATION LOSS (MBH	COMBUST LOSSES (MBH)	FUEL IN (MBH)	COAL FLOW (LBM/HR	FLUE GAS FLOW (LBM/HR	BOILER EFF	CAPACITY RATIO	NTU	EFF	EXIT AIR (F	EXIT WATER (F	FORCED DRAFT (SCFM	INDUCED DRAFT (SCFM)	TOTAL HP	FAN STEAM (LBM/HR	BLOW DOWN FLASH (LBM/HR	TOTAL LO PRES STEAM (LBM/HR
BASELINE	3	2	0	76	5,402	149,697	77.9%	0.64	0.70	0.44	369	302	32,125	33,266	328	7,152	648	17,777
DESIGN	8	2	0	205	14,520	227,811	85.2%	0.33	0.46	0.35	392	258	47,559	50,625	487	9,589	3,810	54,701

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AREA-A COMPUTER BOILER MODEL - BASELINE

BOILER-A.WK3

NT

CONDITION	EXCESS LO PRES STEAM (LBM/HR)	EXCESS LO PRES VENT (LBM/HR)	PRV STEAM (LBM/HR)	TOTAL IN PLANT STEAM (LBM/HR)	TOTAL IN PLANT STEAM (LBM/HR)	STEAM TO LOAD (LBM/HR)	FUEL IN (MBH)	MONTHLY FUEL IN (MBH)	STEAM TO LOAD (MBH)	MAKE UP WATER (MBH)	CHP ENERGY ADDED (MBH)	CHP EFF	STEAM JET (MBH)	FLUE LOSS (MBH)	COMBUSTI LOSS (MBH)	EXCESS STEAM VENT (MBH)
BASELINE	7,439	7,439	0	18,221	16.73%	90,700	152.3	109,690	117	10	107	70.3%	1	29	0	8.607
DESIGN	(6,039)	0	6,039	61,184	9.56%	578,816	818.9	589,622	747	58	689	84.1%	1	108	0	0.000

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PEAK STEAM DEMAND

Area-B:

Peak space heat @ 9°F = 104.4 MBH = 101,600 lbm/hr

Average process load	= 106,982 lbm/hr
Peak process load	= 128,380 lbm/hr (120% diversity factor)
Peak pipe loss	= 22,622 Btu/hr°F (525°F - 9°F) = 11.67 MBH
@ 1028 Btu/lbm	= 11,352 lbm/hr

Total peak Area-B steam demand = 241,332 lbm/hr.

Area-A:

Assume peak steam demand is 120% of peak monthly average.

December 1990 99.6 million pounds of steam produced
x120% diversity factory
117.2 ÷ 720 hrs = 167,700 lbm/hr.

APPENDIX C

COGENERATION ANALYSIS

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STEAM PIPE HEAT LOSS

Existing heat loss for Area-B is estimated at 10.6 MMBtu/hr. The Kinney EEAP determined the steam temperature at 525°F, and the outside air temperature at 56°F.

Heat loss from insulated pipe is presented as:

$$\frac{Q}{L} = \frac{2\pi\, k\, \Delta t}{ln(r_o/r_i) + k/h_o r_o}.$$

Calculated heat loss from the Kinney EEAP is

24" dia 3" insulation = 469.2 Btu/hr/ft.

Backing out k gives

$$\frac{\frac{Q}{L}\, ln\left(\frac{r_o}{r_I}\right)}{2\pi\ \Delta t} = k = 0.036\ Btu/hrft^{\circ}F\ x\ 12\ in/ft = 0.43\ Btu/in/hrft^{2\circ}F.$$

ASHRAE data pipe insulation is set at 300°F = 0.45 Btu/in hr ft^{2}°F.

Therefore, calculated k matches published value.

The heat loss on the pipe measured 105°F with 60°F ambient still air. Thus, heat loss from the pipe is:

$$\frac{469.2\ Btu/ft\,hr}{\pi \frac{30}{12} ft} = 59.7\ Btu/hrft^2.$$

The calculated coefficient is h = 1.33 Btu/hrft^{2}°F, which is a reasonable number. Therefore, it may be concluded that the Kinney EEAP data is accurate.

The steam pipe heat loss coefficient for Area-B is:

$$\frac{10{,}628{,}370\ Btu/hr}{(525 - 56)^{\circ}F} = 22{,}662\ Btu/hr^{\circ}F.$$

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detailed data

EXISTING HEAT LOSS

organization:

contact: EMC ENGINEERS, INC.
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personnel: CHECKED BY 9E DATE 1/28/92
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The existing conditions are as follows:

Pipe Size IPS	Pipe Length Feet	Insulation Thickness Inches	Heat Loss Btu/Hr/Ft	Heat Loss Btu/Hr
24	4150	3	469.2	1,947,180
20	900	3	399.5	359,550
18	4300	3	364.6	1,567,780
14	2600	3	294.6	765,960
12	2550	3	263.9	672,945
10	1350	3	230.0	310,500
8	9260	3	190.9	1,767,734
6	3200	2-1/2	183.5	587,200
4	10730	2-1/2	138.7	1,488,251
3	9350	2-1/2	124.2	1,161,270
TOTAL	39,390			10,628,370

STEAM PIPING CONDENSATE GENERATION

Existing

Pipe loss =	10.6 MBH
Avg. steam demand =	138,283 lbm/hr x 1028 Btu/lbm = 142 MBH

300 psig, 525°F =	300 psig, saturated	
h = 1271 Btu/lbm	h = 1203 Btu/lbm	Δh = 68 Btu/lbm

68 Btu/lbm x 138,283 lbm/hr = 9,403,000 Btuh = 9.4 MBH.

Condensate amount = 10.6 - 9.4 = 1.2 MBH.

Therefore, most heat loss will be absorbed by reduction of superheat.

300 psig latent heat h_{fg} = 803 Btu/lbm
h_f = 399

$$Condensate\ generated = \frac{1{,}200{,}000\ Btuh}{(1203 - 399)\ Btu/lb} = 1492\ lbm/hr.$$

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STEAM USAGE MODEL DEVELOPED FROM STEAM PRODUCTION DATA

SPACE LOAD COEF	BLC	1,865,000	USED TO BALANCE SYSTEM
DISTRIBUTION LOSS COEF	UA	22,622	FROM KINNEY REPORT
PROCESS STEAM	PROC	77,027	AVERAGE SUMMER STEAM DELIVERED
ENTHALPY CHANGE	DH	1,028	HG=1271 (300 PSIG, 525 F STEAM) HF=243 (30 PSIG SAT LIQUID)
IN PLANT STEAM – B	INB	16%	FROM BOILER ANALYSIS
STEAM TEMP	TSTM	525	

		WEATHER		AREA–B BASE ENERGY ANALYSIS							
		AMBIENT TEMP (F)	DEGREE DAYS	METERED STEAM (1000LBM)	IN PLANT STEAM (1000LBM)	DSTRB LOSS (1000LBM)	PROCESS & SPACE (1000LBM)	PROCESS STEAM (1000LBM)	SPACE HEAT STEAM (1000LBM)	DEGREE DAY STEAM (1000LBM)	MODEL MATCH
Jan	89	42	698	140,234	22,998	7,653	109,583	77,027	32,556	30,392	1.5%
Feb	89	40	709	134,104	21,993	7,684	104,427	77,027	27,400	30,870	−2.6%
Mar	89	51	428	139,156	22,822	7,510	108,824	77,027	31,798	18,635	9.5%
Apr	89	55	325	115,466	18,936	7,447	89,083	77,027	12,056	14,151	−1.8%
May	89	60	198	116,416	19,092	7,368	89,956	77,027	12,930	8,621	3.7%
Jun	89	72	1	100,156	16,426	7,177	76,553	77,027	(474)	44	−0.5%
Jul	89	75	0	97,286	15,955	7,130	74,201	77,027	(2,825)	0	−2.9%
Aug	89	73	0	107,224	17,585	7,162	82,478	77,027	5,451	0	5.1%
Sep	89	68	55	101,149	16,588	7,241	77,320	77,027	293	2,395	−2.1%
Oct	89	57	262	121,296	19,893	7,415	93,988	77,027	16,962	11,408	4.6%
Nov	89	46	575	133,138	21,835	7,589	103,714	77,027	26,687	25,036	1.2%
Dec	89	28	1,139	146,538	24,032	7,875	114,631	77,027	37,605	49,593	−8.2%
Jan	90	42	718	133,970	21,971	7,653	104,346	77,027	27,319	31,262	−2.9%
Feb	90	75	540	124,446	20,409	7,130	96,907	77,027	19,880	23,512	−2.9%
Mar	90	74	423	131,516	21,569	7,146	102,802	77,027	25,775	18,418	5.6%
Apr	90	69	303	120,496	19,761	7,225	93,510	77,027	16,483	13,193	2.7%
May	90	58	93	105,546	17,310	7,399	80,837	77,027	3,811	4,049	−0.2%
Jun	90	49	0	108,456	17,787	7,542	83,127	77,027	6,101	0	5.6%
Jul	90	44	0	89,614	14,697	7,621	67,296	77,027	(9,730)	0	−10.9%
Aug	90	39	0	103,116	16,911	7,700	78,505	77,027	1,478	0	1.4%
Sep	90	41	48	100,064	16,410	7,669	75,985	77,027	(1,042)	2,090	−3.1%
Oct	90	49	225	111,766	18,330	7,542	85,895	77,027	8,868	9,797	−0.8%
Nov	90	72	474	124,070	20,347	7,177	96,545	77,027	19,518	20,638	−0.9%
Dec	90	70	636	131,240	21,523	7,209	102,508	77,027	25,481	27,692	−1.7%
Jan	91	0	806	140,030	22,965	8,318	108,747	77,027	31,720	35,094	−2.4%
Feb	91	0	659	129,326	21,209	8,318	99,798	77,027	22,772	28,693	−4.6%
Mar	91	0	483	139,018	22,799	8,318	107,901	77,027	30,874	21,030	7.1%
Apr	91	60	175	131,682	21,596	7,368	102,719	77,027	25,692	7,620	13.7%
May	91	0	32	106,856	17,524	8,318	81,013	77,027	3,987	1,393	2.4%
Jun	91										
Jul	91										
Aug	91										

89	56	4,390	1,452,163	238,155	89,250		924,320	200,437	191,144	0.6%
90	57	3,460	1,384,300	227,025	89,013		924,320	143,942	150,651	−0.5%
AVG	56	3,925	1,418,232	232,590	89,132	0	924,320	172,190	170,898	0.1%

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COGENERATION BASECASE ANALYSIS

BLC	1,865,000		SPACE LOAD COEF
UA	22,622		DISTRIBUTION LOSS COEF
PROC	106,982	LBM/HR	PROCESS DEMAND
PROC300	47,462	LBM/HR	300 PSIG DEMAND
DHNOW	1,028	BTU/LBM	300 PSIG ENERGY CONTENT
DHNEW	1,028	BTU/LBM	EXIT STEAM ENERGY CONTENT
INB	16%		IN PLANT STEAM
TSTM	525		STEAM TEMP
ASR	83	LBM/KW/HR	TURBINE STEAM RATE
SIZE	0	LBM/HR	TURBINE SIZE
BOILEFF	72.00%		
COAL$	1.2500	$/MBTU	
KW$	9.5000	$/KW	
KWH$	0.0159	$/KWH	

		DEGREE DAYS	AMBIENT TEMP (F)	LOW PRES PROCESS (LBM/HR)	300 psig PROCESS (LBM/HR)	HEATING LOAD (LBM/HR)	DSTRB LOSS (LBM/HR)	STEAM DEMAND (LBM/HR)	COGEN STEAM (LBM/HR)	ELECTRIC USAGE (KWH)	ELECTRIC DEMAND (KW)	AVG DEMAND (KW)	TURBINE STEAM (LBM/HR)
Jan	31	930	35	59,520	47,462	54,426	10,783	172,191	124,729	5,545,500	9,235	7,454	0
Feb	28	759	38	59,520	47,462	49,178	10,717	166,877	119,415	4,716,000	8,926	7,018	0
Mar	31	580	46	59,520	47,462	33,943	10,541	151,466	104,004	4,619,000	8,793	6,208	0
Apr	30	375	56	59,520	47,462	22,678	10,321	139,980	92,518	5,047,000	8,815	7,010	0
May	31	111	64	59,520	47,462	6,496	10,145	123,623	76,161	4,513,500	8,650	6,067	0
Jun	30	10	72	59,520	47,462	605	9,969	117,555	70,093	4,621,000	8,904	6,418	0
Jul	31	0	75	59,520	47,462	0	9,903	116,885	69,423	4,944,500	8,948	6,646	0
Aug	31	0	74	59,520	47,462	0	9,925	116,907	69,445	4,618,000	8,992	6,207	0
Sep	30	35	69	59,520	47,462	2,117	10,035	119,133	71,671	4,925,000	9,340	6,840	0
Oct	31	263	57	59,520	47,462	15,391	10,299	132,672	85,210	4,970,500	8,909	6,681	0
Nov	30	564	46	59,520	47,462	34,107	10,541	151,630	104,168	5,012,000	9,045	6,961	0
Dec	31	831	38	59,520	47,462	48,632	10,717	166,331	118,869	5,221,500	9,092	7,018	0
Yr		4,458	56	59,520	47,462	22,298	10,324	139,604	92,142	58,753,500	8,971	6,711	0

AVERAGE STEAM USAGE AND PEAK DEMAND SUMMARY

EMC ENGINEERS, INC.
PROJ. # ______ **PROJECT** ______
SHEET NO. ______ **OF** ______
CALCULATED BY ______ **DATE** ______
CHECKED BY ______ **DATE** ______
SUBJECT ______

PREVIOUS STUDIES

Kinney EEAP

Space Heat Peak Demand = 29,167 lbm/hr Active Buildings Only, Skin Loss Only

Pipe Heat Loss = 22,622 Btu/hr/°F = UA

DuPont Theoretical Process Analysis

Average Process Steam Usage = 63,542 MBtu/month

$$\frac{63{,}542 \times 10^6 \text{ Btu}}{\text{month}} \; \frac{\text{lbm}}{1028 \text{ Btu}} = 61{,}811{,}000 \text{ lbm/month}$$

BASE ENERGY MODEL DEVELOPMENT

1) Tabluated metered boiler steam production from 89 and 90

2) Deducted CHP in plant steam usage (16% of metered)

3) Deducted pipe heat loss

$$UA \times (525°F - TA) \times \text{Days} \times 24$$

4) Remaining steam flow is process and space heat

5) Average summer usage assumed to be all process = 77,027,000 lbm/month

6) Deduct process from total steam to get space heat steam

7) Space load coefficient calcualted using degree days

$$BLC = \frac{\text{Steam}}{\text{DD}} = \frac{172{,}190{,}000 \text{ lbm}}{3925°F \text{ days}} \; \frac{1028 \text{ Btu}}{\text{lbm}} \; \frac{\text{day}}{24 \text{ hrs}} = 1{,}865{,}000 \; \frac{\text{Btu}}{\text{hr°F}}$$

8) For base model, use long-term historical degree days and ambient temperatures

DISTRIBUTION OF STEAM DEMAND

Space Heat Steam Per Building

Base Distribution on EEAP Data

$$\text{Using Correction Factor} = \frac{172{,}190{,}000 \text{ lbm}}{8760 \text{ hrs}} \; \frac{\text{hr}}{29{,}167 \text{ lbm}} = 3.48$$

Process Steam Per Building

Base Distribution on DuPont Study

$$\text{Average Correction Factor} = \frac{77{,}027{,}000 \text{ lbm}}{61{,}811{,}000 \text{ month}} \; \frac{\text{month}}{\text{lbm}} = 1.25$$

Diversity Correction Factor (See Hourly Steam Profile) = 1.20

Job HOLSTON AAP
Location KINGSPORT, TENNESSEE
Subject BUILDING DATA

A. M. KINNEY, INC.
CONSULTING ENGINEERS
CINCINNATI, OHIO
AREA "B"

File No. 02591 Sheet No.
Checked by JAG Date 8-25-82
Computed by ADP Date 8-16-82

EMC ENGINEERS, INC.
PROJ. # PROJECT
SHEET NO. 7 OF 102
CALCULATED BY DATE
CHECKED BY JJL DATE 1/29/82
SUBJECT

BUILDING DATA SHEET
PAGE 4 OF 12

Vol 1 p. 34 Heating Annual Energy Consumed (MBtu)

✓ in use 10/91

TABLE 1 - (CONTINUED) BUILDING DATA SHEETS - PART 2

COLUMN NO'S.

①	②	⑱	⑲	⑳	㉑	㉒	㉓	㉔	㉕	㉖	㉗	㉘	㉙	㉚	
BLDG. NO.	NAME	COOLING		HEATING		PEAK TRANS. LOAD		DOMESTIC HOT WATER		CONNECT LOAD KW	LIGHTING LOAD KW	DEMAND KW	ANNUAL USAGE KWH	Watt Ratio REMARKS	
		SYSTEM	CAPACITY	SYSTEM	FUEL	GAIN	LOSS	CAPACITY	FUEL						
2	CORPS OF ENGINEERS	WINDOW A.C.	--	CONVECT	STEAM	--	401,369	50 GAL	STEAM	61.5	48.5	49.2	12,690	3.0	569.9
4	MEDICAL	WINDOW A.C.	--	CONVECT	STEAM	--	554,425	50 GAL	ELECT	43.0	43.0	30.1	37,690	3.2	1,294
6	GUARD HEADQUARTERS	WINDOW A.C.	--	CONVECT	STEAM	--	403,532	50 GAL	ELECT	35.3	17.3	24.7	30,660	3.2	808.7
7	FIRE HALL	WINDOW A.C.	--	FORCED AIR	OIL	--	524,654	60 GAL	ELECT	33.0	14.5	23.1	28,910		
8	LABORATORY	WINDOW A.C.	--	CONVECT	STEAM	--	618,649	100 GAL	STEAM	166.4	71.0	124.8	86,530	2.09	1,239.8
8A	LABORATORY ANNEX	--	--	U.H. CONVECT	STEAM	--	129,092	--	--	54.4	13.9	40.8	28,290		
8D	SOLVENT STORAGE	--	--	U.H.	STEAM	--	19,474	--	--	6.0	5.2	6.0	720		
9	SUBSTATION	--	--	FORCED AIR	OIL	--	132,600	--	--	9.9	8.4	8.9	360		
12	TRAINING	CENTRAL D.X.	325,000	FORCED AIR	STEAM	140,620	145,500	50 GAL	ELECT	46.4	17.7	41.8	48,260	3.22	273.9
20	SERVICE BUILDING	--	--	--	--	--	--	--	--	--	--	--	--		
26	ADMINISTRATION	CHILLED WATER	135T	FORCED AIR	HOT WATER	864,512	1546,414	50 GAL	ELECT	623.4	310.0	561.0	778,000		
100	MACHINE AND METAL SHOP	WINDOW A.C.	--	U.H. & CONVECT	STEAM	--	4194,515	26 GAL	ELECT	469.2	49.7	328.5	243,985	2.0	8,405.8
101	GENERAL STORES	WINDOW A.C.	--	U.H.	STEAM	--	1089,409	--	--	60.1	28.7	54.0	12,480	2.0	2,183.2
102	INST. AND ELECTRIC SHOP	--	--	U.H.	ELECT	--	2119,662	52 GAL	ELECT	76.0	38.0	60.6	39,520	2.0	4,247.8
103	"Receiving" STORAGE WAREHOUSE	WINDOW A.C.	--	U.H.	STEAM	--	2325,452	--	--	99.6	23.7	10.0	1,200	2.0	1,604.6 ?
104	CARPENTER SHOP	--	--	U.H. & CONVECT	STEAM	--	446,700	--	--	77.4	14.9	38.8	40,250	3.22	895.2
105	SERVICE STATION	--	--	U.H.	STEAM	--	336,445	52 GAL	ELECT	17.4	17.4	12.2	48,800	3.22	674.2
106	LAUNDRY	--	--	U.H. & CONVECT	STEAM	--	825,644	1600 GAL	STEAM	116.4	40.4	87.3	60,230		
108	CHANGE HOUSE	--	--	U.H.	STEAM	--	321,330	60 GPM	STEAM	31.3	31.3	28.2	32,550	2.09	643.9

Job HOLSTON AAP
Location KINGSPORT, TENN.
Subject BUILDING DATA

A. M. KINNEY, INC.
CONSULTING ENGINEERS
CINCINNATI, OHIO
AREA "B"

File No 02591 Sheet No
Checked by JAG Date 8/25/82
Computed by ADP Date 8/16/82

EMC ENGINEERS, INC.
PROJ. # PROJECT
SHEET NO. 8 OF
CALCULATED BY DATE
CHECKED BY DATE
SUBJECT

BUILDING DATA SHEET
PAGE 6 OF 12

Vol 1, P. 34

TABLE 1 - (CONTINUED) BUILDING DATA SHEETS - PART 2

COLUMN NO'S.

①	②	⑱	⑲	⑳	㉑	㉒	㉓	㉔	㉕	㉖	㉗	㉘	㉙	㉚
BLDG. NO.	NAME	COOLING		HEATING		PEAK TRANS. LOAD		DOMESTIC HOT WATER		CONNECT LOAD KW	LIGHTING LOAD KW	DEMAND KW	ANNUAL USAGE KWH	Wall R value REMARKS / Annual Heating Energy MBtu
		SYSTEM	CAPACITY	SYSTEM	FUEL	GAIN	LOSS	CAPACITY	FUEL					
110	CAFETERIA	CENTRAL D.X.	120,000	U.H. & CONV.	STEAM	--	282,370	27 GPM	STEAM	42.3	34.7	38.0	43,990	
116	AUTO PAINT SHOP	--	--	U.H. & CONV.	STEAM	--	375,172	6 GAL	ELEC	35.1	19.0	28.0	36,500	2.0 751.8
118	PAINT & LUBE STG.	--	--	U.H.	STEAM	--	128,448	--	--	5.1	5.1	--	--	STORAGE
119	GUARD STATION	--	--	CONV.	ELEC.	--	54,225	32 GAL	ELEC.	7.8	7.8	7.0	34,165	
127	S & M OFFICE QUANSET	CENTRAL D.X.	120,000	FORCED AIR	STEAM	78,756	131,111	52 GAL	ELEC	42.7	22.5	38.4	44,410	12.0 257.0
135	CLOCK STA. BUTLER	WINDOW A.C.	--	FAN COIL	STEAM	--	177,953	52 GAL	ELEC	33.4	11.2	30.0	17,370	
136	DATA PROCESSING	CENTRAL D.X.	462,000	FORCED AIR,U.H.	GAS STEAM	156,037	133,654	32 GAL	ELEC.	85.0	40.4	76.5	88,400	
150	LACQUER PREP.	WINDOW A.C.	--	U.H.	ELEC STEAM	--	240,907	--	--	28.7	23.8	25.8	3,100	
151	HEXAMINE	--	--	U.H. CONVECT	STEAM	--	449,805	--	--	47.9	25.4	43.0	4,980	
155	PRODUCTION OFFICE	CENTRAL D.X.	480,000	FORCED AIR	ELEC.	429,891	308,814	520 GAL	ELEC.	348.8	85.1	279.0	253,525	
156	SHOP & OFFICE	CENTRAL D.X.	170,000	UNIT HTRS FORC.AIR	STEAM	127,481	507,570	550 GAL	ELEC.	173.5	98.5	138.8	126,310	
157	DECONTAMINATION BDG	--	--	U.H. CONVECT	STEAM	--	62,728	20 GAL	ELEC.	27.3	8.3	7.0	3,300	
200	STEAM PLANT	--	--	U.H.	STEAM	--	PROC.	--	--	420.0	36.0	320.2	870,200	
203	FILTER PLANT	WINDOW A.C.	--	U.H. CONVECT	~~OIL~~ Propane	--	657,824	82 GAL	ELEC.	65.9	31.6	59.3	144,320	2.13 1,318.3
216	FILTER TRTM'T PLNT	--	--	U.H.	ELEC	--	75,600	--	--	113.8	74.3	102.4	348,910	
219	CHANGE HOUSE & SHOP	--	--	U.H.	STEAM	--	236,553	182 GAL	ELEC	26.3	17.0	23.7	13,675	
220	BATTERY CHARG'G STA.	--	--	--	--	--	--	--	--	28.3	5.5	25.5	5,885	
224	CHEMICAL FEED BLDG.	--	--	U.H.	ELEC.	--	89,026	--	--	64.2	3.2	18.2	3,285	
225	BATTERY CHG'G STA.	--	--	--	--	--	--	--	--	28.3	5.5	25.5	5,885	
226	BATTERY CHG'G STA.	--	--	--	--	--	--	--	--	28.3	5.5	25.5	5,885	
229	BATTERY CHG'G STA.	--	--	--	--	--	--	--	--	28.3	5.5	25.5	5,885	
230	INCINERATOR	--	--	U.H.	GAS	--	438,647	6 GAL	ELEC	34.8	34.8	31.3	3,755	
231	COMPRESSED AIR	--	--	U.H.	STEAM	--	85,976	--	--	883.7	27.5	795.3	183,810	

Job HOLSTON AAP
Location KINGSPORT, TENN.
Subject BUILDING DATA

A. M. KINNEY, INC.
CONSULTING ENGINEERS
CINCINNATI, OHIO
AREA "B"

File No. 02591 Sheet No
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Computed by ADP Date 8/16/82

EMC ENGINEERS, INC.
PROJ. # PROJECT
SHEET NO. 7 OF 183
CALCULATED BY DATE
CHECKED BY DATE
SUBJECT

BUILDING DATA SHEET
PAGE 8 OF 12

TABLE 1 - (CONTINUED) BUILDING DATA SHEETS - PART 2

COLUMN NO'S.

(1)	(2)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)	(27)	(28)	(29)	(30)
BLDG. NO.	NAME	COOLING		HEATING		PEAK TRANS. LOAD		DOMESTIC HOT WATER		CONNECT LOAD KW	LIGHTING LOAD KW	DEMAND KW	ANNUAL USAGE KWH	REMARKS
		SYSTEM	CAPACITY	SYSTEM	FUEL	GAIN	LOSS	CAPACITY	FUEL					
232	IND. WASTE PUMP STA. #1	--	--	U.H.	ELECT	--	44,445	--	--	350.0	8.0	320.3	185,286	
234	IND. WASTE PUMP STA. #2	--	--	U.H.	ELECT.	--	46,340	--	--	200.0	2.0	140.1	80,900	
235	WASTE TREATMENT	CENTRAL D.X.	229,200	U.H. & FCD AIR	ELECT.	249,774	736,568	120 GAL	ELECT.	1,269.3	28.1	1,143.2	7,034,000	
302B	AMMONIA OXIDATION PL	--	--	U.H.	STEAM	--	296,833	--	--	42.3	6.3	36.1	236,658	
302BB	PUMP HOUSE	--	--	U.H.	STEAM	--	44,683	--	--	12.1	6.1	8.9	5,620	
315	OFFICE & LAB NITRIC ACID	WINDOW A.C.	--	U.H. & FCD AIR	STEAM	-- 1	489,573	30 GAL	ELEC	16.8	7.1	15.1	8,735	
321	REPAIR SHOP & OFFICE	--	--	UH & CONV.	ELEC STEAM	--	372,215	--	--	12.1	6.5	10.9	6,290	
322	CHANGE HOUSE NITRIC ACID	WINDOW A.C.	--	U.H.	STEAM	--	331,095	60 GPM	STEAM	29.2	29.2	26.3	15,185	
328	ACID AREA OFFICE	CENTRAL D.X.	100,000	CONV & FCD AIR	STEAM	127,400	90,300	32 GAL	ELEC.	25.2	11.7	22.7	13,105	
334	MAGNESIUM NITRATE	--	--	CONV.	STEAM	--	1293,930	--	--	776.2	12.9	620.9	403,625	
335	CONT. HOUSE FOR 334	--	--	U.H.	ELEC.	--	45,098	--	--	(IN	CLUDED IN BUILDIN	G 334)		
339	MAINTENANCE SHOP	--	--	U.H. & CONV.	STEAM	--	201,961	50 GAL	ELECT.	101.8	14.7	91.6	52,935	
556	HEAVY EQUIP. SHOP	--	--	U.H. & CONV.	STEAM	--	597,686	--	--	138.0	18.3	111.0	201,700	
580	ROADS & GROUNDS BUILDING	WINDOW A.C.	--	U.H. & CONV.	STEAM	--	359,150	--	--	10.1	9.2	9.0	1,000	
634	HAAP QUALITY ASSURANCE OFFICE	WINDOW A.C.	--	U.H. & CONV.	ELEC.	--	59,624	52 GAL	ELEC	34.2	11.7	26.9	136,300	
A	AMMONIA RECOVERY	--	--		STEAM	--	32,858	--	--	61.8	2.3	55.6	32,135	
B1	PRIMARY RECOVERY SLUDGE	--	--	CONV.	STEAM	-	383,603	--	--	61.8	32.6	55.6	32,135	
B3	PRIMARY RECOVERY SLUDGE	--	--	CONVECT	STEAM	--	383,603	--	--	774.3	12.2	618.6	402,380	
C3	LACQ. PREP. 503/4	--	--	U.H. & CONV.	STEAM	--	372,680	--	--	150.7	13.5	107.0	169,525	
C5	HEXAMINE SOLUTION	--	--	U.H. & CONV.	STEAM	--	372,680	--	--	150.7	13.5	107.0	169,525	

Job HOLSTON AAP
Location KINGSPORT, TENN.
Subject BUILDING DATA AREA "B"

A. M. KINNEY, INC.
CONSULTING ENGINEERS
CINCINNATI, OHIO

File No 02591 Sheet No.
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EMC ENGINEERS, INC.
PROJ. # PROJECT
SHEET NO. 10 OF 10?
CALCULATED BY DATE
CHECKED BY DATE
SUBJECT

BUILDING DATA SHEET
PAGE 10 OF 12

COLUMN NO'S.

TABLE 1 - (CONTINUED) BUILDING DATA SHEETS - PART 2

1	2	18	19	20	21	22	23	24	25	26	27	28	29	30
BLDG. NO.	NAME	COOLING		HEATING		PEAK TRANS. LOAD		DOMESTIC HOT WATER		CONNECT LOAD KW	LIGHTING LOAD KW	DEMAND KW	ANNUAL USAGE KWH	REMARKS
		SYSTEM	CAPACITY	SYSTEM	FUEL	GAIN	LOSS	CAPACITY	FUEL					
C6	PILOT PLANT	--	--	CONVECT	STEAM	--	297,955	--	--	267.6	13.5	221.3	143,830	
D3	NITRATION	--	--	CONVECT	STEAM	--	PROC.	--	--	336.3	19.3	269.0	147,875	
D5	NITRATION	--	--	CONVECT	STEAM	--	PROC.	--	--	336.3	19.3	269.0	147,875	
D6	NITRATION	--	--	CONVECT	STEAM	--	PROC.	--	--	336.3	19.3	269.0	147,875	
E1	WASHING	WINDOW A.C.	--	CONVECT	STEAM	--	PROC.	--	--	287.4	13.4	229.9	159,700	
E3	WASHING	--	--	CONVECT	STEAM	--	PROC.	--	--	287.4	13.4	229.9	159,700	
E4	WASHING	--	--	CONVECT	STEAM	--	PROC.	--	--	287.4	13.4	229.9	159,700	
E6	WASHING	--	--	CONVECT	STEAM	--	PROC.	--	--	287.4	13.4	229.9	159,700	
F3	CHANGE HOUSE	WINDOW A.C.	--	U.H.	STEAM	--	412,945	60 GPM	STEAM	47.9	47.9	43.1	424,910	
F5	CHANGE HOUSE	--	--	U.H.	STEAM	--	412,945	60 GPM	STEAM	43.0	43.0	38.7	236,658	
G1	PURIFICATION	--	--	CONVECT	STEAM	--	PROC.	--	--	240.	21.8	192.0	133,311	
G3	PURIFICATION	--	--	CONVECT	STEAM	--	PROC.	--	--	138.8	20.8	111.0	201,700	
G4	PURIFICATION	--	--	CONVECT	STEAM	--	PROC.	--	--	153.3	20.6	122.6	208,500	
G5	PURIFICATION	--	--	CONVECT	STEAM	--	PROC.	--	--	138.8	20.8	111.0	201,700	
G6	PURIFICATION	--	--	CONVECT	STEAM	--	PROC.	--	--	187.5	24.4	150.0	220,158	
H1	FILTER & WEIGHING	--	--	U.H. & CONVECT	STEAM	--	199,458	--	--	124.2	7.3	99.4	93,770	
H3	FILTER & WEIGHING	--	--	U.H. & CONVECT	STEAM	--	199,458	--	--	124.2	7.3	99.4	93,770	
H4	FILTER & WEIGHING	--	--	U.H. & CONVECT	STEAM	--	199,458	--	--	124.2	7.3	99.4	93,770	
H5	FILTER & WEIGHING	--	--	U.H. & CONVECT	STEAM	--	199,458	--	--	124.2	7.3	99.4	93,770	
H6	FILTER & WEIGHING	--	--	U.H. & CONVECT	STEAM	--	199,458	--	--	124.2	7.3	99.4	93,770	
I3	INCORPORATION	--	--	CONVECT FAN CL	STEAM	--	301,485	--	--	31.1	17.5	24.9	162,800	
I4	INCORPORATION	--	--	CONVECT FAN CL	STEAM	--	301,485	--	--	32.8	15.0	26.2	183,400	
I6	INCORPORATION	--	--	CONVECT FAN CL	STEAM	--	301,485	--	--	31.5	18.2	25.2	176,300	
J3	INCORPORATION	--	--	CONVECT FAN CL	STEAM	--	301,485	--	--	38.7	17.6	31.0	164,600	
J4	INCORPORATION	--	--	CONVECT FAN CL	STEAM	--	301,485	--	--	40.4	15.0	23.3	163,200	

Job HOLSTON AAP
Location KINGSPORT, TENN.
Subject BUILDING DATA

A. M. KINNEY, INC.
CONSULTING ENGINEERS
CINCINNATI, OHIO
AREA "B"

File No. 02591 Sheet No
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EMC ENGINEERS, INC.
PROJ. # PROJECT
SHEET NO. 11 OF 12
CALCULATED BY DATE
CHECKED BY DATE
SUBJECT

BUILDING DATA SHEET

TABLE 1 - (CONTINUED) BUILDING DATA SHEETS - PART 2

COLUMN NO'S.

(1)	(2)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)	(27)	(28)	(29)	(30)
BLDG. NO.	NAME	COOLING		HEATING		PEAK TRANS. LOAD		DOMESTIC HOT WATER		CONNECT LOAD KW	LIGHTING LOAD KW	DEMAND KW	ANNUAL USAGE KWH	REMARKS
		SYSTEM	CAPACITY	SYSTEM	FUEL	GAIN	LOSS	CAPACITY	FUEL					
J5	INCORPORATION	--	--	CONVECT FAN COIL	STEAM	--	301,485	--	--	39.1	18.2	31.3	180,320	
K3	TNT OPENING	--	--	CONVECT	STEAM	--	130,875	--	--	34.5	12.1	27.6	136,300	
K5	TNT OPENING	--	--	CONVECT	STEAM	--	114,340	--	--	30.2	4.7	24.2	129,800	
L3	INCORPORATION	--	--	CONVECT FAN COIL	STEAM	--	301,485	--	--	39.2	18.2	35.3	191,200	
L4	INCORPORATION	--	--	CONVECT FAN COIL	STEAM	--	301,485	--	--	39.2	18.2	35.3	191,200	
L6	INCORPORATION	--	--	CONVECT FAN COIL	STEAM	--	301,485	--	--	39.2	18.2	35.3	191,200	
M3	INCORPORATION	--	--	CONVECT FAN COIL	STEAM	--	301,485	--	--	46.2	17.6	41.6	235,460	
M4	INCORPORATION	--	--	CONVECT FAN COIL	STEAM	--	301,485	--	--	46.2	15.0	42.0	234,800	
M5	INCORPORATION	--	--	CONVECT FAN COIL	STEAM	--	301,485	--	--	46.8	18.2	42.1	236,200	
M6	INCORPORATION	--	--	CONVECT FAN COIL	STEAM	--	301,485	--	--	46.8	18.2	42.1	236,200	
N3	PACKAGING BUILDING	--	--	U.H.	STEAM	--	182,701	--	--	32.9	7.5	29.6	194,800	
N4	PACKAGING BUILDING	--	--	U.H.	STEAM	--	257,280	--	--	43.7	12.4	39.3	198,900	
N5	PACKAGING BUILDING	--	--	U.H.	STEAM	--	182,701	--	--	31.2	10.2	28.1	191,200	
N6	PACKAGING BUILDING	--	--	U.H.	STEAM	--	257,280	--	--	30.0	11.5	27.0	132,200	
03	ANALYTICAL	CENTRAL D.X.	48,000	FAN COIL	STEAM	--	76,085	40 GAL	STEAM	12.8	12.8	11.5	100,100	
05	ANALYTICAL	--	--	FAN COIL	STEAM	--	76,085	40 GAL	STEAM	12.8	12.8	11.5	100,100	
P3	CHANGE HOUSE	--	--	U.H.	STEAM	--	503,540	60 GPM	STEAM	59.1	59.1	53.2	420,400	
R3	SHOP & OFFICE	WINDOW A.C.	--	U.H.	STEAM	--	29,690	--	--	5.9	5.9	4.8	40,100	
W1	OFFICE	--	--	CONVECT	STEAM	--	47,846	30 GAL	ELEC	2.9	1.9	2.3	3,555	
Y1	BOX RECONDITION	--	--	--	--	--	--	--	--	8.2	8.2	7.4	4,265	

EMC ENGINEERS, INC.
PROJ. #_____ PROJECT _____
SHEET NO. _____ OF _____
CALCULATED BY _____ DATE _____
CHECKED BY _____ DATE _____
SUBJECT _____

FOR FINDING PROCESS LOADS

Assume: Similar buildings produce Similar Loads.

For G-buildings:

The G-buildings produce

14.4 batches/day x 30 days/mo = 432 batches/mo.

The total process energy added = 8,918,000 Btu/batch.

For one month:

8,918,000 Btu/batch x 432 batches/mo = 3,852,580,000 Btu/mo.

Therefore, the G-buildings process is 3,852,580,000 Btu/mo.

The amount removed is:

8,380,000 x 432 = 3,620,160,000 Btu/mo.

To put this in the units of lb/hr,

Added:

$$\frac{3{,}852{,}580{,}000\ Btu}{month} x \frac{1\ month}{3\ days} x \frac{1\ day}{24\ hr} x \frac{1\ lb}{1028\ Btu} = 5205.06\ lb/hr.$$

Removed:

$$\frac{3{,}620{,}160{,}000\ Btu}{1\ month} x \frac{1\ month}{30\ days} x \frac{1\ day}{24\ hr} x \frac{1\ lb}{1028\ Btu} = 4891.05\ lb/hr.$$

HOLSTON ARMY AMMUNITION PLANT
PROCESS ENERGY INVENTORY
HMX RECRYSTALIZATION AND COATING, BUILDING G-6

EQUIPMENT OR STREAM	HEAT ADDED 1000 Btu	HEAT ADDED Source	HEAT ADDED lb.	HEAT REMOVED 1000 Btu	HEAT REMOVED Source	HEAT REMOVED Gal.	HEAT LOST 1000 Btu	HEAT LOST Source	HEAT LOST Mode	Comments
										Basis: One batch (850# HMX, 5070# water, 26,000# acetone)
Equipment:										
1. Dissolver	2,070	38 lb. Steam	2,247				91		Conv.	Heat loss to surroundings.
2. Still	6,235	38 lb. Steam	6,779	509	F.W.	3,054	432	Shell	Conv.	382 gpm for 8 hours. Heat loss to surroundings
3. Condenser				7,165	F.W.	43				
Streams:										
Stream 1	20	E-Bldg.	3,370							Product from E-Building.
Stream 2				533	H-Bldg.					Product to H-Building.
Stream 3	593	Sparge	547							Sparged steam becomes process water.
Stream 4				173	Decant	1,924				Decant from still.
Total Process Energy	8,918			8,380			523			Imbalance: Negligible

TABLE 18

EMC ENGINEERS, INC.
PROJ. #_____ PROJECT _____
SHEET NO. 14 OF 10
CALCULATED BY KK DATE _____
CHECKED BY _____ DATE _____
SUBJECT _____

FACILITY APPRAISAL
PRODUCT: CLASS 1 HMX
CODE: 6805

PROD	BLDG.	PROCESS/ EQUIPMENT	UNITS	MAN PWR	BATCH SIZE	CYCLE TIME	% RW	% LT	BA/DAY SCHD	LB/HR SCHD	SF	BA/DAY ACTUAL	LB/HR ACTUAL	LB/MO ACTUAL
HMX		RECRYST.												
CLASS 1	605	HA1	1	3	850	375	.005	5	3.8	136.0	.95	3.65	129	92632
CLASS 1	605	HA1	2	3	850	375	.005	5	7.6	269.2	.95	7.22	256	183334
CLASS 1	605	HA1	3	3	850	375	.005	5	11.4	403.8	.95	10.83	384	275001
CLASS 1	605	HA1	4	4	850	375	.005	10	15.2	538.3	.90	13.68	484	347369 BUILDING CAPACITY

NOTES:

* AVERAGE CYCLE TIME WAS CALCULATED USING DATA FROM 605, 606, AND 607.

CYCLE TIME IS COUNTED FROM START OF DISSOLVER CHARGE THRU DECANTING.

BUILDING 6-5 IS EQUIPPED WITH ONLY THREE (3) DISSOLVERS. AT A RATE REQUIRING FOUR SYSTEMS ADDITIONAL LOST TIME IS INCURRED DUE TO THE SHARING OF A DISSOLVER.

IF H-5 IS DECANTING, ONE STILL WILL BE REQUIRED TO PROCESS DECANT WATER.

STATISTICS
HMX SPC PROGRAM

ATTRIBUTE	AVG.	STD.DEV.	COUNT	MIN.	MAX.
1. CYCLE TIME - RECRY.	375	25.4	94	290	430

Data Source: Random batches from 6-5, 6-6, and 6-7.

2. % RW .005
Data Source: Batches reworked due to screen pot failure and alpha from 6-5, 6-6, and 6-7.

3. BA.WT. 848 89.6

4. % YIELD: 99.8

YIELD = Average batch weight divided by standard weight.

REVIEW DATE: 11/21/89

APPROVAL: M H Smith
D. L. Bacon

EMC ENGINEERS, INC.
PROJ. # ____ PROJECT ____
SHEET NO. ____ OF ____
CALCULATED BY ____ DATE ____
CHECKED BY ____ DATE ____
SUBJECT ____

EMC ENGINEERS, INC.
PROJ. #______ PROJECT [illegible]
SHEET NO: [illegible] OF [illegible]
CALCULATED BY______ DATE______
CHECKED BY______ DATE______
SUBJECT______

FACILITY APPRAISAL
PRODUCT: COMP A-3, TYPE II
CODE: 007

PRODUCT	BLDG.	PROCESS/ EQUIPMENT	NO. EQ	MAN PWR	BATCH SIZE	CYCLE TIME	% RW	% LT	BA/DAY SCHD	LB/HR SCHD	SF	BA/DAY ACTUAL	LB/HR ACTUAL	LB/MO ACTUAL	CAP/ RATE
COMP A-3,II	G03	COATING		5	4960	49.3	10.0	5.0	29.2	6032	.864	25.21	5210	3735447	BLDG CAP
	G03	DISSOLVER	3		4500	105.0	10.0	5.0	13.7	2571	.864	11.84	2221	1592299	EQUIP RATE
	G03	STILL	3		4960	148.0	10.0	5.0	9.7	2011	.864	8.40	1737	1245149	EQUIP RATE
	G03	MELT POT	2		76										
COMP A-3,II	G04	COATING		5	4960	49.3	10.0	5.0	29.2	6032	.864	25.21	5210	3735447	BLDG CAP
	G04	DISSOLVER	3		4500	105.0	10.0	5.0	13.7	2571	.864	11.84	2221	1592299	EQUIP RATE
	G04	STILL	3		4960	148.0	10.0	5.0	9.7	2011	.864	8.40	1737	1245149	EQUIP RATE
	G04	MELT POT	2		76										
COMP A-3,II	H03	DEWATER		3	4960	136.0	10.0	5.0	10.6	2188	.864	9.14	1890	1355015	BLDG CAP
	H03	VAC.SYSTEM	1		4960	136.0	10.0	5.0	10.6	2188	.864	9.14	1890	1355015	EQUIP RATE
COMP A-3,II	H04	DEWATER		3	4960	68.0	10.0	5.0	21.2	4376	.864	18.29	3780	2710030	BLDG CAP
	H04	VAC.SYSTEM	2		4960	136.0	10.0	5.0	10.6	2188	.864	9.14	1890	1355015	EQUIP RATE

NOTES:

COMP A-3, TYPE II COATING :

ONE COMP A-3 BATCH IS PROCESSED FOR EACH MELT POT (MGCL2) BATCH.

COATING CAPABILITIES LIMITED BY ONLY 3 STILLS (5, 7, AND 8) EQUIPPED WITH MELT POTS.

COMP A-3, TYPE II DEWATERING :

TIME REQUIRED TO TRANSPORT NUTSCHES TO DRYING BUILDING IS NOT INCLUDED.

STATISTICS

ATTRIBUTE	AVG.	STD.DEV.	COUNT	MIN.	MAX.
1. CYCLE TIME					
DISSOLVER:	105	31.6	64	55	215
STILL:	148	32.2	80	90	305
VAC.SYSTEM:	136	26.0	70	60	215

Data Source: 1988 and 1989 production records (batch sheets).

2. % RW 10.0
Data Source: Since Composition A-3, Type II is a new product and production has been limited to only 80 batches, a rework value of 10 % will be used until more data is accumulated.

REVIEW DATE: 11/20/89

APPROVAL: [illegible signature]

FOR BUILDING 334

Total process energy added:

20,529,000 Btu/hr x 24 hr/day x 30 day/mo = 14,780.9 MBtu/mo.

In lb/hr:

20,529,000 Btu/hr x 1 lb/1028 Btu = 19,969.8 lb/hr.

Total process energy removed:

20,077,000 Btu/hr x 24 hr/day x 30 day/mo = 14,455.4 MBtu/mo.

In lb/hr,

120,077,000 Btu/hr x 1 lb/1028/Btu = 19,530.2 lb/hr.

EMC ENGINEERS, INC.
PROJ. #______ PROJECT 3172-[illegible]
SHEET NO. 16 OF 10[illegible]
CALCULATED BY [illegible] DATE [illegible]
CHECKED BY________ DATE__________
SUBJECT______________________

EMC ENGINEERS, INC.
PROJ. #______ PROJECT ______
SHEET NO. 17 OF 10_
CALCULATED BY______ DATE______
CHECKED BY______ DATE______
SUBJECT ______

HOLSTON ARMY AMMUNITION PLANT
PROCESS ENERGY INVENTORY
NITRIC ACID CONCENTRATION, BUILDING 334

Equipment or Stream	Heat Added: 1000 Btu/hr	Heat Added: Source	Heat Added: lb/hr	Heat Removed: 1000 Btu/hr	Heat Removed: Source	Heat Removed: Gal/min.	Heat Lost: 1000 Btu/hr	Heat Lost: Source	Heat Lost: Mode	Comments
Equipment:										
Base heater heat exchanger	5,151	300 psig Steam	6,399							
Evaporator heat exchanger	3,430	300 psig Steam	4,260				49	Shell	R&C*	*Radiation and convection losses from shell.
$Mg(NO_3)_2$ mix tank				35**	CW					**Equivalent hourly loss of exothermic reaction. (5815KBtu per week)
Strip Condenser				3,623	CW	329				
Distillation Column	11,659	Influent		10,865	Effluent		794	Shell	R&C	
Absorption column				146	CW	73				
Product condensers				3,589	CW	1,793				
Cascade cooler				406	CW	1,793				Same cooling water as used at condensers.
Process Streams:										
23 Product to storage				111						These streams add or remove sensible heat from the boundary of the process system.
21 Weak HNO_3 recovered				56						
24 Strip condensate				403						
2 Weak HNO_3 feed	289									
Total Process Heat	20,529		10,659	20,077						Imbalance = 2%
Other Energy:										
Absorption column steam jet	198	100 psig Steam	166							300 psig steam reduced via PRV to 100 psig
Evaporator steam jet	282	150 psig Steam	236							300 psig steam reduced via PRV to 150 psig
Electric motors	438	Elec.								172 HP operate continuously.

TABLE 31

FOR THE D-BUILDINGS

Total process energy added:

616,000 Btu/batch
419 batch/day ⇒ 1,470 batch/mo.

616,000 Btu/batch x 1470 batch/mo = 905.52 MBtu/mo.

In lb/hr,

905.52 MBtu/mo x 1 mo/30 days x 1 day/24 hr x 1 lb/1028 Btu = 1,223 lb/hr.

Total process energy removed:

637,000 Btu/batch x 1470 batch/mo = 936.39 MBtu/mo.

In lb/hr,

936.39 MBtu/mo x 1 mo/30 day x 1 day/24 hr x 1 lb/1028 Btu = 1265.12 lb/hr.

EMC ENGINEERS, INC.
PROJ. #_____ PROJECT 3102-[illegible]
SHEET NO. 15 OF _____
CALCULATED BY [illegible] DATE [illegible]
CHECKED BY_____ DATE_____
SUBJECT _____

EMC ENGINEERS, INC.
PROJ. # ______ PROJECT ______
SHEET NO. ______ OF 102
CALCULATED BY ______ DATE ______
CHECKED BY ______ DATE ______
SUBJECT ______

HOLSTON ARMY AMMUNITION PLANT
PROCESS ENERGY INVENTORY
HMX NITROLYSIS, BUILDING D-6

Equipment or Stream	Heat Added 1000 Btu	Heat Added Source	Heat Added lb.	Heat Removed 1000 Btu	Heat Removed Source	Heat Removed GPM	Heat Lost 1000 Btu	Heat Lost Source	Heat Lost Mode	Comments
Equipment:										Basis: 1 Nitrator Batch
Chem. 501/521 Heat Exchanger	2.7	30 psig Steam	2.9							Heated in summer only; cooled in winter due to heated boxway.
Chem. 503/504 Heat Exchanger	4.3	30 psig Steam	4.7							
Nitrator	3.0	30 psig Steam	3.2							Heat required to heat up heel.
	119	Reaction		119	Ch.W.	93				? 175K Btu per hour peak load
	85	Reaction		85	Ch.W.	97				(331K Btu per hour average load).
	56	Reaction								Heat of Reaction absorbed by feed.
	17.85			17.85	F.W.	6				54K Btu per hour from two N-Batches
Age Tank	163	30 psig Steam	176	154	F.W.	42				Acetic Anhydride - Water Reaction. Heat required to maintain 100°C for 4-hours.
Simmer Tank	57	Reaction								
	31	30 psig Steam	33				31	Shell	R&C	Radiation and Convection from Shell.
Streams:										
Chem. 509 Feed	16.0									
Chem. 521 Feed	9.3									
Chem. 501/521 Feed	8.1									
Chem. 503/504 Feed	13.0									
Dilution Liquor to Simmer Tk.	30.6			230						Imbalance = 3%
Product Slurry to E-Bldg.				637						
Total Process Energy	616									
Other Energy:										
Boxway Heating	333		359							Btu/hr. to maintain 140°F inside for 500' length to E-Building.
Refrigeration Unit	10,470									

Kingsport, Tennessee

TABLE 14

ATTACHMENT 1

EMC ENGINEERS, INC.
PROJ. #_____ PROJECT _____
SHEET NO. _____ OF 103
CALCULATED BY_____ DATE_____
CHECKED BY_____ DATE_____
SUBJECT _____

FACILITY APPRAISAL
PRODUCT: CRUDE RDX
CODE: 6300

PRODUCT	BLDG.	PROCESS/ EQUIPMENT	NO. EQ	MAN PWR	BATCH SIZE	CYCLE TIME	% RW	% LT	BA/DAY SCHD	LB/HR SCHD	SF	BA/DAY ACTUAL	LB/HR ACTUAL	LB/MO ACTUAL	CAP/ RATE
CRUDE RDX	D01	NITRATION		3	4785	34.2		10.0	42.1	8400	.900	37.92	7560	5420520	BLDG CAP
	D01	REACTOR 1 (70#/MIN)	1		4785	68.4		10.0	21.1	4200	.900	18.96	3780	2710260	EQUIP RATE
	D01	REACTOR 2 (70#/MIN)	1		4785	68.4		10.0	21.1	4200	.900	18.96	3780	2710260	EQUIP RATE
CRUDE RDX	D02	NITRATION		3	4785	54.4		10.0	26.5	5280	.900	23.83	4752	3407184	BLDG CAP
	D02	REACTOR 1 (44#/MIN)	1		4785	108.8		10.0	13.2	2640	.900	11.92	2376	1703592	EQUIP RATE
	D02	REACTOR 2 (44#/MIN)	1		4785	108.8		10.0	13.2	2640	.900	11.92	2376	1703592	EQUIP RATE
CRUDE RDX	D03	NITRATION		3	4785	39.9		10.0	36.1	7195	.900	32.48	6476	4643249	BLDG CAP
	D03	REACTOR 1 (60#/MIN)	1		4785	79.8		10.0	18.0	3598	.900	16.24	3238	2321624	EQUIP RATE
	D03	REACTOR 2 (60#/MIN)	1		4785	79.8		10.0	18.0	3598	.900	16.24	3238	2321624	EQUIP RATE
CRUDE RDX	D07	NITRATION		3	4785	43.1		9.0	33.4	6660	.910	30.40	6061	4345450	BLDG CAP
	D07	REACTOR 1 (61#/MIN)	1		4785	78.4		9.0	18.4	3660	.910	16.71	3331	2388040	EQUIP RATE
	D07	REACTOR 2 (50#/MIN)	1		4785	95.7		9.0	15.0	3000	.910	13.69	2730	1957410	EQUIP RATE
CRUDE RDX	D08	NITRATION		3	4785	36.8		10.0	39.1	7802	.900	35.22	7021	5034392	BLDG CAP
	D08	REACTOR 1 * (65#/MIN)	1		4785	73.6		10.0	19.6	3901	.900	17.61	3511	2517196	EQUIP RATE
	D08	REACTOR 2 * (65#/MIN)	1		4785	73.6		10.0	19.6	3901	.900	17.61	3511	2517196	EQUIP RATE

ATTACHMENT 2

FACILITY APPRAISAL
PRODUCT: HMX CRUDE
CODE: 6800

PROD	BLDG.	PROCESS/ EQUIPMENT	UNITS	MAN PWR	BATCH SIZE	CYCLE TIME	% RW	% LT	BA/DAY SCHD	LB/HR SCHD	SF	BA/DAY ACTUAL	LB/HR ACTUAL	LB/MO ACTUAL	CAP/RATE
HMX CRUDE	D-5	NITRATION	2	4	680	26.35		9.7	54.65	1548	90.3	49.35	1398	1002565	BLDG. CAP
HMX CRUDE	D-5	NITRATION	2	3	680	26.35		28.2	54.65	1548	71.8	39.23	1111	796897	LBR. RATE
HMX CRUDE	D-5	NITRATION	1	2	680	52.70		32.7	27.32	774	67.3	18.39	521	373580	LBR. RATE
HMX CRUDE	D-5	NITRATOR	EA		680	52.70		9.7	27.32	774	90.3	24.67	699	501252	EQUIP. RATE

NOTES:

THE OPERATION REQUIRES TWO OPERATORS MINIMUM DURING OPERATION OF THE NITRATOR. THUS, THREE OPERATORS ARE REQUIRED TO KEEP ONE NITRATOR OPERATIONAL FULL TIME.

THREE OPERATORS ARE REQUIRED DURING SIMULTANEOUS OPERATION OF TWO NITRATORS FULL TIME. WHEN ONLY TWO OPERATORS ARE PRESENT, ONLY ONE NITRATOR MAY BE OPERATED. THIS RESTRICTION IS REFLECTED IN THE SCHEDULED BATCHES FOR THE TWO-OPERATOR/THREE-NITRATOR SITUATION. FOUR OPERATORS CAN OPERATE BOTH NITRATORS FULL TIME WITH VIRTUALLY NO RESTRICTIONS.

THE BATCH SIZE ASSUMED IS THEORETICAL BASED ON OPERATIONS TO DATE.

% LT IS BASED ON HISTORICAL INFORMATION RELATED TO AVAILABILITY OF FACILITIES, WHICH INCLUDES THE EXTRA TIME REQUIRED FOR THIS FACILITY DURING 90-DAY SHUTDOWNS, BOILOUT OF NITRATORS AND AGE TANKS, ROUTINE CALIBRATION OF EQUIPMENT, NON-ROUTINE MAINTENANCE, AND EQUIPMENT FAILURES. ADDITIONAL LOST TIME FOR MISCELLANEOUS EMPLOYEE CONSTRAINTS SUCH AS MEDICAL CHECKS, TRAINING, ACCIDENTS, RECEIVING CHEMICALS AT BUILDING C-5, AND INVENTORY MONITORING IS INCLUDED FOR OPERATION OF TWO NITRATORS WITH THREE PEOPLE AND ONE NITRATOR WITH TWO PEOPLE.

STATISTICS: (CYCLE TIME)

AVERAGE	STD. DEV.	COUNT	MIN.	MAX.
57.2	1.92	394	50.02	65.02

DATA SOURCE: BUILDING D-5 BATCHES (10/1 - 10/17/89)

REVIEW DATE: 11/21/89

APPROVAL: Mike Rothrock

R. L. Bacon

EMC ENGINEERS, INC.
PROJ. # ____ PROJECT ____
SHEET NO. ____ OF ____
CALCULATED BY ____ DATE ____
CHECKED BY ____ DATE ____
SUBJECT ____

BUILDING 302-B

Total process energy added = 18,273,000 Btu/hr.

18,273,000 Btu/hr x 24 hr/day x 30 day/mo = 13,156.6 MMBtu/mo.

In lb/hr,

18,273,000 Btu/hr x 1 lb/1028 Btu = 17,775.3 lb/hr.

Total process energy removed = 18,645,000 Btu/hr.

18,645,000 Btu/hr x 24 hr/day x 30 day/mo = 13,424.4 MBtu/mo.

In lb/hr,

18,645,000 Btu/hr x 1 lb/1028 Btu = 18,137 lb/hr.

EMC ENGINEERS, INC.
PROJ. #_____ PROJECT ________
SHEET NO. _____ OF ______
CALCULATED BY _____ DATE ______
CHECKED BY ______ DATE ______
SUBJECT ______________

EMC ENGINEERS, INC.
PROJ. # ______ PROJECT ______
SHEET NO. ______ OF ______
CALCULATED BY ______ DATE ______
CHECKED BY ______ DATE ______
SUBJECT ______

HOLSTON ARMY AMMUNITION PLANT
PROCESS ENERGY INVENTORY
NITRIC ACID MANUFACTURING, BUILDING 302-B

Equipment	Heat Added			Heat Recovered			Heat Removed			Heat Lost			Comments
	1000 Btu/hr	Source	lb/hr	1000 Btu/hr	Donor	Recipient	1000 Btu/hr	Source	Gal/min	1000 Btu/hr	Source	Rate	
Ammonia Vaporizer	631.9	Steam	694							69.4		.2 gpm	Basis: 45 TPD production.
Converter	6280	Reaction		563	Ammonia	Product Gas	1,740	R.W.	77.5				
				2100	Air	Product Gas							
PRE-Compressor	1536	Elect.					3,400	R.W.	329				
										307	Machine		Mechanical & electrical losses
XRD-Compressor				1082	Tail Gas	Air				60	Exhaust Gas		318.8 hp-hr/hr 75% turbine efficiency.
Air Preheater							2,100	Air	16,556*				
Tail Gas Heater							1,440	Tail Gas	15,450*				*Pounds per hour.
Cascade Cooler	4733	Reaction	17,644				7,963	R.W.	581				
Absorption Tower	1331	Reaction					1,453	R.W.	581				
	16.3	Condensate Feed	1,256										
Bleacher										112.5	61% Acid	6147 lb/hr	
Total Process Energy	18,273 Added or Recovered						18,645 Removed or Lost						Imbalance = 2%

TABLE 28

FOR E-BUILDINGS

Total process energy = 559,000 Btu/hr.

559,000 Btu/hr x 24 hr/day x 30 day/mo = 402,480,000 Btu/mo.

In lb/hr,

559,000 Btu/hr x 1 lb/1028 Btu = 543,774 lb/hr.

EMC ENGINEERS, INC.
PROJ. #_____ PROJECT _____
SHEET NO. 24 OF _____
CALCULATED BY _____ DATE _____
CHECKED BY _____ DATE _____
SUBJECT _____

EMC ENGINEERS, INC.
PROJ. # ______ PROJECT ______
SHEET NO. 25 OF 102
CALCULATED BY ______ DATE ______
CHECKED BY ______ DATE ______
SUBJECT ______

HOLSTON ARMY AMMUNITION PLANT
PROCESS ENERGY INVENTORY
EXPLOSIVES WASHING, BUILDING E-6

	Energy			
Equipment	1000 Btu/hr	Source	Average Hourly Rate	Comments
Mix tank agitators	29.57 (8.66 kJ/s)	Elect.	8.6 kW	Seven agitators @ 20 hp (14.9 kW) each run, 2 hours per day.
Pumps	66.67 (19.5 kJ/s)	Elect.	19.5 kW	Seven pumps @ 15 hp (11 kW) each run, 6 hours per day.
Vacuum jets	559 (163.7 kJ/s)	100 psig Steam (690 kPa)	470 lb/hr (59.2 g/s)	Two of four vacuum jets run continuously.

TABLE 16

EMC ENGINEERS, INC.
PROJ. #______ PROJECT [illegible]
SHEET NO. 26 OF 102
CALCULATED BY______ DATE______
CHECKED BY______ DATE______
SUBJECT______

FACILITY APPRAISAL
PRODUCT: CRUDE RDX
CODE: 6300

PRODUCT	BLDG.	PROCESS/ EQUIPMENT	NO. EQ	MAN PWR	BATCH SIZE	CYCLE TIME	% RW	% LT	BA/DAY SCHD	LB/HR SCHD	SF	BA/DAY ACTUAL	LB/HR ACTUAL	LB/MO ACTUAL	CAP/ RATE
CRUDE RDX	E01	NO FA RATE													
CRUDE RDX	E02	FILTER/WASH			4675	60.0		12.0	24.0	4675	.880	21.12	4114	2949738	BLDG CAP
	E02	WASH TANK	6		4675	360.0		12.0	4.0	779	.880	3.52	686	491623	EQUIP RATE
CRUDE RDX	E03	FILTER/WASH		4	4675	55.0		5.5	26.2	5100	.945	24.74	4820	3455582	BLDG CAP
REGULAR	E03	WASH TANK	6		4675	330.0		5.5	4.4	850	.945	4.12	803	575930	EQUIP RATE
CLASS 5	E03	WASH TANK	6		2338	195.0		5.5	7.4	719	.945	6.98	680	487430	EQUIP RATE
CLASS 7	E03	WASH TANK	6		4675	410.0		5.5	3.5	684	.945	3.32	647	463554	EQUIP RATE
CRUDE RDX	E07	FILTER/WASH		3	4675	40.0		13.0	36.0	7013	.870	31.32	6101	4374327	BLDG CAP
	E07	WASH TANK	6		4675	240.0		13.0	6.0	1169	.870	5.22	1017	729055	EQUIP RATE
CRUDE RDX	E08	FILTER/WASH		5	4675	36.0		15.0	40.0	7800	.850	34.04	6630	4753710	BLDG CAP
	E08	BELTFILTER	1		4675	36.0		15.0	40.0	7800	.850	34.04	6630	4753710	EQUIP RATE
CRUDE RDX	E09	FILTER/WASH			4675	62.3		5.0	23.1	4500	.950	21.95	4275	3065175	BLDG CAP
	E09	WASH TANK	6		4675	374.0		5.0	3.9	750	.950	3.66	713	510863	EQUIP RATE
CRUDE RDX	E10	FILTER/WASH			4675	64.9		7.0	22.2	4324	.930	20.65	4022	2883456	BLDG CAP
	E10	WASH TANK	6		4675	389.2		7.0	3.7	721	.930	3.44	670	480576	EQUIP RATE

FACILITIES APPRAISAL
BY PRODUCT

HMX CRUDE-BATCH
PRODUCT CODE - 6800

DATE REVISED	BLDG	PROCESS OR EQUIPMENT	NO EQ	MAN PWR	BATCH SIZE	TIME	% RWK	% LT	B/D SCHD	LB/HR SCHD	SF	B/D ACTUAL	LB/HR ACT	LB/MO ACT	CAP/ RATE
6/20/85	D06	NITRATION	3	4	170	17.3		11	83.07	588	89	73.93	523	375469	BLDG CAP
6/20/85	D06	NITRATION	2	3	170	26.0		11	55.38	392	89	49.29	349	250292	LBR RATE
6/20/85	D06	NITRATION	1	2	170	52.0		11	27.69	196	89	24.64	174	125146	LBR RATE
6/20/85	D06	NITRATOR	3		170	52.0		11	27.69	196	89	24.64	174	125146	EQUIP RATE
	D06	A TWO OPERATOR PER SHIFT STAFFING LEVEL CREATES A "LONE													
	D06	OPERATOR" SITUATION DURING MEALS AND BREAK TIMES. THIS													
	D06	SITUATION IS UNACCEPTABLE UNLESS PROVISIONS ARE MADE TO													
	D06	PREVENT THE LONE OPERATOR SITUATION FROM OCCURRING, OR													
	D06	TO ALLEVIATE THE PROBLEMS INHERENT IN IT (E.G., PROVIDE													
	D06	RELIEF DURING MEALS AND BREAK OR USE THE AID OF A "LONE													
	D06	OPERATOR" DEVICE).													
6/18/75	E04	WASHING HMX-BATCH		2	850	133.3		31	10.80	382	69	7.45	263	189228	BLDG CAP
6/17/85	E04	WASH TANKS	6		850	800.0		31	1.80	63	69	1.24	43	31518	EQUIP RATE
	E04	MATERIAL RECEIVED FROM D-6.													
6/ 4/74	E05	WASHING HMX-BATCH			850	180.0		2	8.00	283	98	7.84	277	199057	BLDG CAP
6/ 4/74	E05	WASH TANKS	8		850	144.0		2	1.02	36	98	1.00	35	25363	EQUIP RATE
	E05	THIS RATE IS FOR HMX RECEIVED FROM D-5.													
6/ 4/74	E05	WASHING HMX-BATCH			850	100.0		31	14.40	509	69	9.94	351	252294	EQUIP RATE
6/ 4/74	E05	WASH TANKS	8		850	800.0		31	1.80	63	69	1.24	43	31518	EQUIP RATE
	E05	THIS RATE IS FOR HMX RECEIVED FROM D-6.													
6/20/85	E06	WASHING HMX-BATCH			680	.0		8	30.72	870	92	28.26	800	574137	BLDG CAP
6/20/85	E06	WASHING HMX-BATCH		2	680	.0		8	20.09	569	92	18.48	523	375469	LBR RATE
6/20/85	E06	WASHING HMX-BATCH		1	680	.0		8	11.52	326	92	10.60	300	215279	LBR RATE
6/20/85	E06	WASH TANKS	8		680	375.0		8	3.84	108	92	3.53	100	71759	EQUIP RATE
	E06	STAFFING IN BUILDING E-6 BECOMES QUESTIONABLE AT													
	E06	PRODUCTION RATES GREATER THAN BUILDING D-6 CAPABILITY,													
	E06	WHICH IS 375,470 LBS/MO. ADDITIONAL AID WOULD BE													
	E06	NECESSARY TO OPERATE THE BUILDING AT A HIGHER RATE WITH													
	E06	TWO OPERATORS PER SHIFT (E.G., LINE CLEANERS ASSISTANCE													
	E06	IN NORMAL AND PEAK INDIRECT ACTIVITIES). PROVISIONS													
	E06	WOULD BE NECESSARY TO OPERATE THE BUILDING WITH A SINGLE													
	E06	OPERATOR PER SHIFT (E.G., MEAL AND BREAK TIME RELIEF													

EMC ENGINEERS, INC.
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CALCULATED BY ____ DATE ____
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FACILITY APRAISAL
PRODUCT: HMX CRUDE
CODE: 6800

ATTACHMENT 2

PROD	BLDG.	PROCESS/ EQUIPMENT	UNITS	MAN PWR	BATCH SIZE	CYCLE TIME	% RW	% LT	BA/DAY SCHD	LB/HR SCHD	SF	BA/DAY ACTUAL	LB/HR ACTUAL	LB/MO ACTUAL	CAP/RATE
HMX CRUDE	E-6	FILT/WASH	8	3	680	51.08		9.9	28.00	793	90.1	25.23	715	512507	BLDG. CAP.
HMX CRUDE	E-6	FILT/WASH	8	2	680	51.08		9.9	19.00	538	90.1	17.12	485	347772	LBR. RATE
HMX CRUDE	E-6	WASH TANKS	EA		680	408.60		9.9	3.50	99	90.1	3.15	89	64063	EQUIP. RATE

NOTES:

THE CAPABILITY OF THE FACILITY IS LIMITED SOMEWHAT BY THE CAPACITY OF THE CHEMICAL 522 STORAGE TANKS. WASH TANK FILTRATION TIME LOST DUE TO DELAYS FROM BUILDING D-5 FOR BOILOUTS CANNOT BE MADE UP. A THREE OPERATOR STAFF IS REQUIRED AT THIS LEVEL OF OPERATION BECAUSE OF EXTRA STORAGE TANK PUMPING AND CLEANING.

CYCLE TIMES ARE BASED ON HISTORICAL DATA FOR BUILDING D-5 HMX ONLY AND INCLUDE THE FILTRATION, WASHING, RESLURRYING, TRANSFERRING, AND WARM WASHING OF THE CLOTH IN PREPARATION FOR THE NEXT BATCH.

%LT IS BASED ON HISTORICAL INFORMATION RELATED TO THE AVAILABILITY OF THE FACILITIES, WHICH INCLUDES TIME LOST DURING NITRATOR BOILOUTS, NON-ROUTINE MAINTENANCE OF EQUIPMENT, FILTER CLOTH CHANGES, LINE CLEANING, AND EQUIPMENT AND UTILITY FAILURES.

STATISTICS: (CYCLE TIME)

AVERAGE	STD. DEV.	COUNT	MIN.	MAX.
408.60	43.56	1314	540	279

DATA SOURCE: BUILDING E-6 BATCHES (10/1 - 10/17/89).

REVIEW DATE: 11/21/89

APPROVAL: Mike Rothrock
D. L. Bacon

EMC ENGINEERS, INC.
PROJ. #____ PROJECT 3?02-??2
SHEET NO. 23 OF 1??
CALCULATED BY____ DATE____
CHECKED BY____ DATE____
SUBJECT____

SUMMARY OF PEAK PROCESS AND SPACE HEATING STEAM LOADS FOR AREA-B BUILDINGS

LOADS.WK3

BLDG NO	PEAK SPACE HEAT (BTUH)	PEAK SPACE STEAM (LBM/HR)	CORRECT SPACE STEAM (LBM/HR)	THEORETICAL PROCESS LOAD (MBtu/month)	THEO PROCESS STEAM (LBM/HR)	CORRECT PROCESS STEAM (LBM/HR)	PEAK PROCESS STEAM (LBM/HR)	TOTAL STEAM STEAM (LBM/HR)	POINT OF USE (NODE)
[illegible]	401,369	390	1,359					1,427	69
4	554,425	539	1,877					1,971	69
6	403,532	393	1,366					1,434	69
8	618,649	602	2,094					2,199	68
8A	129,092	126	437					459	68
8D	19,474	19	66					69	68
12	145,000	141	491					515	69
26	1,546,414	1,504	5,235					5,497	69
100	4,194,515	4,080	14,199					14,909	67
101	1,089,409	1,060	3,688					3,872	67
102	2,119,662	2,062	7,176					7,534	67
103	2,325,452	2,262	7,872					8,266	67
104	446,700	435	1,512					1,588	67
105	336,445	327	1,139					1,196	67
106	825,644	803	2,795					2,935	67
108	321,330	313	1,088					1,142	67
110	282,370	275	956					1,004	67
116	375,172	365	1,270					1,334	67
118	128,448	125	435					457	67
127	131,111	128	444					466	67
135	177,953	173	602					633	67
136	133,654	130	452					475	67
150	240,907	234	816					856	67
151	449,805	438	1,523					1,599	67
156	507,570	494	1,718					1,804	67
157	62,728	61	212					223	67
231	85,976	84	291					306	1
302B	PROCESS			13,157	17,775	22,219	26,663	27,996	5
302BI	44,683	43	151					159	5
315	489,573	476	1,657					1,740	5
321	372,215	362	1,260					1,323	5
322	331,095	322	1,121					1,177	5
328	90,300	88	306					321	5
334	PROCESS			14,781	19,970	24,962	29,955	31,453	5
339	201,961	196	684					718	5
556	597,686	581	2,023					2,124	5
580	359,150	349	1,216					1,277	5
A	32,858	32	111					117	32
B1	383,603	373	1,299					1,364	80
B3	383,603	373	1,299					1,364	80
B6	PROCESS			13,323	18,000	22,500	27,000	28,350	80
C3	372,680	363	1,262					1,325	89
C5	372,680	363	1,262					1,325	57
C6	297,955	290	1,009					1,059	60
D3	PROCESS			906	1,223	1,529	1,835	1,927	89
D5	PROCESS			906	1,223	1,529	1,835	1,927	56
E3	PROCESS			402	544	680	816	856	54
E4	PROCESS			402	544	680	816	856	36
E6	PROCESS			402	544	680	816	856	59
F3	412,945	402	1,398					1,468	67
F5	412,945	402	1,398					1,468	58
G3	PROCESS			3,853	5,205	6,506	7,808	8,198	32
G4	PROCESS			3,853	5,205	6,506	7,808	8,198	30
G5	PROCESS			3,853	5,205	6,506	7,808	8,198	33
G6	PROCESS			3,853	5,205	6,506	7,808	8,198	33
G7	PROCESS			3,853	5,205	6,506	7,808	8,198	14
H1	199,458	194	675					709	88
H3	199,458	194	675					709	35
H4	199,458	194	675					709	35
H5	199,458	194	675					709	33
H6	199,458	194	675					709	33
I3	301,485	293	1,021					1,072	23
I4	301,485	293	1,021					1,072	26
I6	301,485	293	1,021					1,072	39
J3	301,485	293	1,021					1,072	22
J4	301,485	293	1,021					1,072	26
J5	301,485	293	1,021					1,072	37
K3	130,875	127	443					465	25
K5	114,340	111	387					406	38
L3	301,485	293	1,021					1,072	21
L4	301,485	293	1,021					1,072	26
L6	301,485	293	1,021					1,072	39
M3	301,485	293	1,021					1,072	20
M4	301,485	293	1,021					1,072	26
M5	301,485	293	1,021					1,072	38
M6	301,485	293	1,021					1,072	39
N3	182,701	178	618					649	20
N4	257,280	250	871					914	26
N5	182,701	178	618					649	38
N6	257,280	250	871					914	39
O3	76,085	74	258					270	20
O5	76,085	74	258					270	26
P3	503,540	490	1,705					1,790	20
R3	29,690	29	101					106	20
W1	47,846	47	162					170	10
TOTAL	29,983,756	29,167	101,501	63,542	85,849	107,311	128,773	241,788	

NODES	TOTAL STEAM LOAD (LBM/HR)
1	306
5	68,287
10	170
14	8,198
20	3,887
21	1,072
22	1,072
23	1,072
25	465
26	5,471
30	8,198
32	8,315
33	17,814
35	1,418
36	856
37	1,072
38	2,127
39	4,129
54	856
56	1,927
57	1,325
58	1,468
59	856
60	1,059
67	51,760
68	2,727
69	10,844
80	31,077
88	709
89	3,252
	241,788

EMC ENGINEERS, INC.
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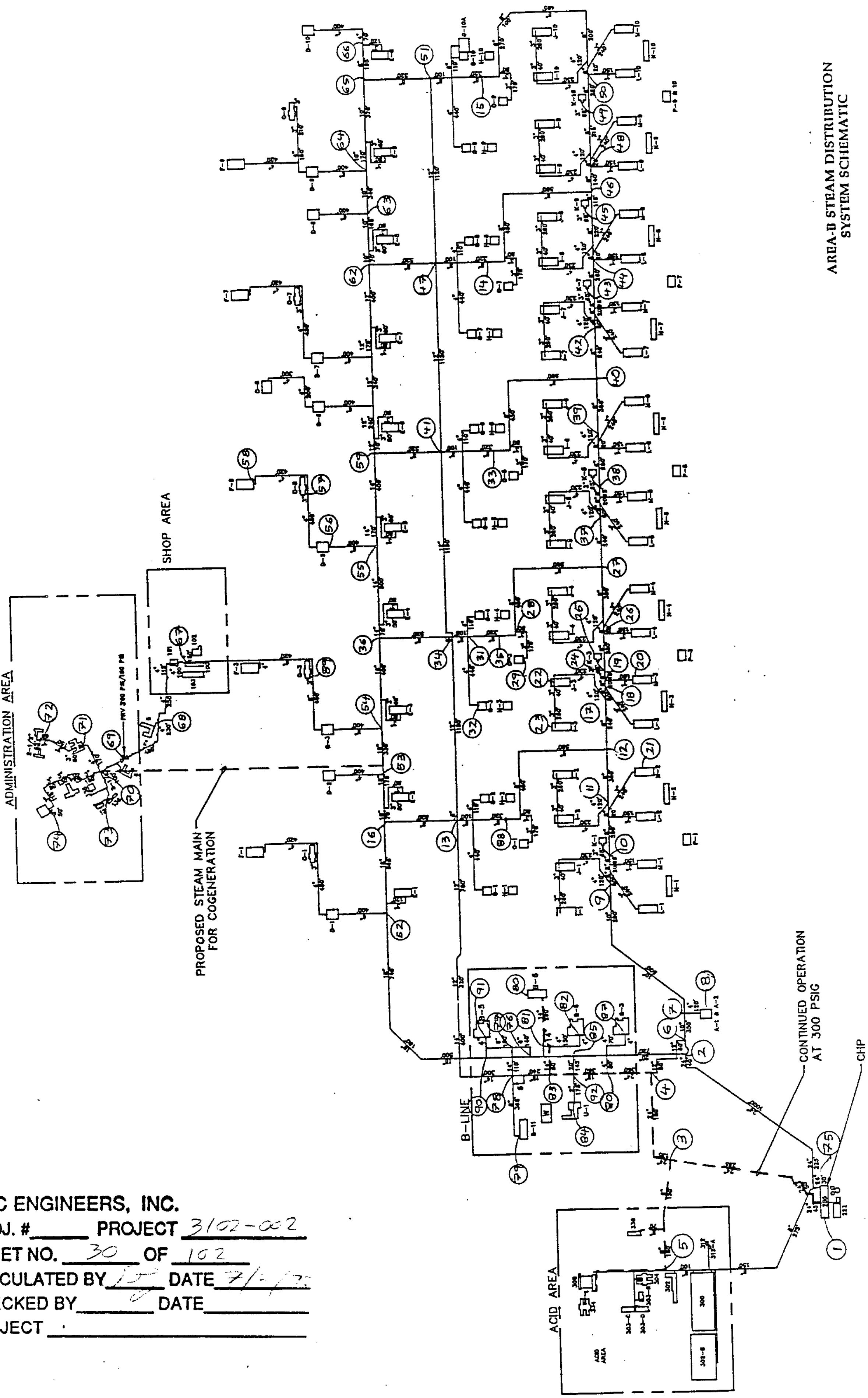

EMC ENGINEERS, INC.

PROJ. #______ PROJECT 3102-002

SHEET NO. 30 OF 102

CALCULATED BY [illegible] DATE 7/[illegible]

CHECKED BY________ DATE________

SUBJECT ________

0TITLE GIVEN TO NETWORK ---------------------- /210 PSIA FLOW MODEL

ESTON AREA B
0ALL DEMAND FLOWS ARE MULTIPLIED BY .0003
0PIPES 100
NODES 91
SOURCE PUMPS 0
BOOSTER PUMPS 0
RESERVOIRS 1
MINOR LOSSES 0
PRVS 0
NOZZLES 0
CHECK VALVE 0
BACK PRES. V. 0
DIF. HEAD DEV 0
SPECIFIED PRES 0

EMC ENGINEERS, INC.
PROJ. #______ PROJECT ______
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DEMANDS AT PUMP OR RES. NODES NOT AL. FOR PUMP OR RES. 1 AT NODE 1
A D. .085 WAS GIVEN. WILL BE SET TO 0.
TO GIVE EST. OF INFLOW SET NPERCT=1
RES.(NOZZLE) PIPES & THEIR ELEV. ARE
101 80640.0
N9= 100 N8= 90

0JUNCTION	EXT.	FLOW	PIPES AT JUNCTION			
1	2	.000	-2	3	95	
2	3	.000	-1	97	102	
3	5	18.984	-103			
4	6	.000	-3	4	-102	
5	7	.000	-4	5	6	
6	8	.000	-5			
7	9	.000	-6	7		
8	10	.047	-7	8		
9	11	.000	-8	9		
10	12	.000	-9	10	12	
11	13	.000	-11	31	96	
12	14	2.279	-44	45		
13	15	.000	-50	51		
14	16	.000	-31	79	-80	
15	17	.000	-12	14	15	
16	18	.000	13	-15	16	
17	19	.000	-16	17	19	
18	20	1.081	-19			
19	21	.298	-13			
20	22	.298	-14	20		
21	23	.298	-20			
22	24	.000	-17	18	21	
23	25	.129	-18			
24	26	1.521	-21	22		
25	27	.000	-22	23	32	
26	28	.000	-23	24	25	
27	29	.000	-24			
28	30	2.279	-27			
29	31	.000	-26	27	28	29
30	32	2.312	-28			
31	33	4.952	-36	37		
32	34	.000	-29	30	66	-96
33	35	.394	-25	26		
34	36	.238	-30	67	-68	

35	37	.298	-32	33		
36	38	.591	-33	34		
37	39	1.148	-34	35		
38	40	.000	-35	36	38	
39	41	.000	-37	39	-65	-66
40	42	.000	-38	40		
41	43	.000	-40	41		
42	44	.000	-41	42		
43	45	.000	-42	43		
44	46	.000	-43	44	46	
45	47	.000	-45	-47	-64	65
46	48	.000	-46	48		
47	49	.000	-48	49		
48	50	.000	-49	50		
49	51	.000	-51	52	64	
50	52	.000	80	-83		
51	53	.000	78	-79		
52	54	.238	68	69	-78	
53	55	.000	60	61	-67	
54	56	.536	-61	62		
55	57	.368	-62	63		
56	58	.408	-63			
57	59	.238	-39	59	-60	
58	60	.294	58	-59		
59	61	.000	57	-58		
60	62	.000	47	56	-57	
61	63	.000	55	-56		
62	64	.000	54	-55		
63	65	.000	-52	53	-54	
64	66	.000	-53			
65	67	14.389	-70	71		
66	68	.758	-71	72		
67	69	.399	-72	73		
68	70	.000	-73	74	76	77
69	71	1.528	-74	75		
70	72	.945	-75			
71	73	.451	-76			
72	74	1.528	-77			
73	75	.000	1	2	-101	103
74	76	.000	-88			
75	77	.000	85	87	88	
76	78	.000	-86			
77	79	.000	-85			
78	80	8.639	-89			
79	81	.000	89	-92		
80	82	.000	-99			
81	83	.000	86	-90	92	
82	84	.000	-93			
83	85	.000	-91	93	-94	99
84	86	.000	90	-97		
85	87	.000	-82			
86	88	.197	-10	11		
87	89	.904	-69	70		
88	90	.000	83	84	-87	91
89	91	.000	-84			
)0	93	.000	82	94	-95	

EMC ENGINEERS, INC.
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O: LOW FROM PUMPS AND RESERVOIRS EQUALS 68.968

ITERATION= 1 SUM= .442E+02
ITERATION= 2 SUM= .146E+02

```
ITERATION=    3 SUM=   .623E+01
ITERATION=    4 SUM=   .203E+01
ITERATION=    5 SUM=   .182E+00
ITERATION=    6 SUM=   .177E-02
UNITS OF SOLUTION ARE
DIAMETERS -  inch
LENGTH -  feet
HEADS -  feet
ELEVATIONS -  feet
PRESSURES -  (psi)
FLOWRATES -  (wt/s)
 DARCY-WEISBACH FORMULA USED FOR COMPUTING HEAD LOSS
1PIPE DATA
```

EMC ENGINEERS, INC.
PROJ. #_____ PROJECT _____
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	PIPE NO.	NODES FROM	TO	LENGTH	DIAM	COEF	FLOW RATE	VELOCITY	HEAD LOSS	HLOSS /1000
	1	75	3	688.	24.0	.000150	20.78	17.64	15.01	21.83
	2	75	2	1315.	24.0	.000150	29.20	24.79	54.76	41.64
*	3	6	2	50.	10.0	.000150	5.44	26.59	6.57	131.33
	4	6	7	350.	10.0	.000150	6.70	32.78	68.52	195.77
	5	7	8	120.	4.0	.000150	.00	.00	.00	.00
	6	7	9	890.	10.0	.000150	6.70	32.78	174.23	195.77
	7	9	10	195.	8.0	.000150	6.70	51.22	116.63	598.12
	8	10	11	280.	8.0	.000150	6.66	50.86	165.20	590.01
	9	11	12	370.	8.0	.000150	6.66	50.86	218.30	590.01
	10	12	88	1170.	8.0	.000150	1.67	12.77	49.94	42.68
	11	88	13	260.	8.0	.000150	1.47	11.26	8.78	33.75
	12	12	17	240.	8.0	.000150	4.99	38.09	81.22	338.43
	13	18	21	240.	3.0	.000150	.30	16.19	50.80	211.67
	14	17	22	390.	4.0	.000150	.60	18.21	73.29	187.91
	15	17	18	80.	8.0	.000150	4.39	33.54	21.22	265.23
	16	18	19	20.	8.0	.000150	4.09	31.26	4.64	231.91
	17	19	24	95.	8.0	.000150	3.01	23.00	12.29	129.42
	18	24	25	65.	3.0	.000150	.13	7.02	2.92	44.85
	19	19	20	150.	3.0	.000150	1.08	58.70	368.76	2458.38
	20	22	23	260.	3.0	.000150	.30	16.19	55.03	211.67
	21	24	26	280.	8.0	.000150	2.88	22.02	33.35	119.09
	22	26	27	370.	8.0	.000150	1.36	10.40	10.76	29.08
*	23	28	27	1010.	8.0	.000150	.39	2.99	2.94	2.91
	24	28	29	250.	3.0	.000150	.00	.00	.00	.00
*	25	35	28	160.	8.0	.000150	.39	2.99	.47	2.91
*	26	31	35	160.	8.0	.000150	.79	6.00	1.68	10.48
	27	31	30	110.	4.0	.000150	2.28	69.64	268.30	2439.06
	28	31	32	440.	4.0	.000150	2.31	70.64	1103.10	2507.04
*	29	34	31	100.	8.0	.000150	5.38	41.07	39.11	391.09
*	30	36	34	520.	8.0	.000150	2.67	20.39	53.54	102.96
*	31	16	13	520.	8.0	.000150	3.94	30.06	111.94	215.27
	32	27	37	240.	8.0	.000150	1.75	13.39	11.19	46.64
	33	37	38	195.	8.0	.000150	1.45	11.11	6.42	32.91
	34	38	39	280.	8.0	.000150	.86	6.59	3.49	12.47
*	35	40	39	370.	8.0	.000150	.28	2.18	.60	1.63
	36	40	33	1170.	8.0	.000150	.82	6.25	13.24	11.32
*	37	41	33	260.	8.0	.000150	4.13	31.58	61.48	236.45
*	38	42	40	240.	8.0	.000150	1.10	8.43	4.72	19.68
	39	59	41	520.	8.0	.000150	2.15	16.40	35.51	68.28
*	40	43	42	195.	8.0	.000150	1.10	8.43	3.84	19.68
*	41	44	43	280.	8.0	.000150	1.10	8.43	5.51	19.68
*	42	45	44	240.	8.0	.000150	1.10	8.43	4.72	19.68
*	43	46	45	115.	8.0	.000150	1.10	8.43	2.26	19.68

* 44	14	46	1170.	8.0	.000150	.25	1.93	1.53	1.31
* 45	47	14	260.	8.0	.000150	2.53	19.34	24.23	93.19
* 46	48	46	140.	8.0	.000150	.85	6.50	1.70	12.16
47	62	47	520.	8.0	.000150	1.53	11.70	18.86	36.2[illegible]
48	49	48	235.	8.0	.000150	.85	6.50	2.86	12.1[illegible]

.PE DATA

PIPE NO.	NODES FROM	TO	LENGTH	DIAM	COEF	FLOW RATE	VELOCITY	HEAD LOSS	HLOSS /1000
* 49	50	49	260.	8.0	.000150	.85	6.50	3.16	12.16
* 50	15	50	1245.	8.0	.000150	.85	6.50	15.14	12.16
* 51	51	15	260.	8.0	.000150	.85	6.50	3.16	12.16
* 52	65	51	520.	8.0	.000150	1.14	8.68	10.80	20.78
53	65	66	195.	8.0	.000150	.00	.00	.00	.00
54	64	65	540.	10.0	.000150	1.14	5.56	3.77	6.99
55	63	64	340.	10.0	.000150	1.14	5.56	2.38	6.99
56	62	63	235.	10.0	.000150	1.14	5.56	1.64	6.99
57	61	62	575.	12.0	.000150	2.67	9.06	8.04	13.98
58	60	61	340.	12.0	.000150	2.67	9.06	4.75	13.98
59	59	60	310.	12.0	.000150	2.96	10.06	5.27	17.00
60	55	59	570.	14.0	.000150	5.35	13.34	13.73	24.09
61	55	56	400.	6.0	.000150	1.31	17.82	44.76	111.90
62	56	57	450.	4.0	.000150	.78	23.73	139.31	309.57
63	57	58	420.	4.0	.000150	.41	12.47	38.81	92.40
64	51	47	1120.	12.0	.000150	.29	.97	.26	.23
* 65	41	47	1150.	12.0	.000150	.71	2.43	1.41	1.23
66	34	41	1150.	12.0	.000150	2.70	9.17	16.46	14.31
67	36	55	570.	14.0	.000150	6.66	16.61	20.76	36.4[illegible]
68	54	36	400.	18.0	.000150	9.57	14.43	8.35	20.8[illegible]
69	54	89	850.	8.0	.000150	20.90	159.68	4666.05	5489.47
70	89	67	1025.	6.0	.000150	20.00	271.60	22448.07	21900.56
71	67	68	595.	4.0	.000150	5.61	171.40	8443.01	14189.93
72	68	69	480.	4.0	.000150	4.85	148.23	5118.93	10664.43
73	69	70	100.	4.0	.000150	4.45	136.05	901.16	9011.57
74	70	71	170.	4.0	.000150	2.47	75.56	485.81	2857.69
75	71	72	290.	3.0	.000150	.94	51.32	550.03	1896.67
76	70	73	100.	2.5	.000150	.45	35.30	114.78	1147.76
77	70	74	585.	3.0	.000150	1.53	83.02	2816.25	4814.10
78	53	54	330.	18.0	.000150	30.71	46.34	63.49	192.38
79	16	53	245.	18.0	.000150	30.71	46.34	47.13	192.38
80	52	16	565.	18.0	.000150	34.64	52.27	137.17	242.77
82	93	87	50.	4.0	.000150	.00	.00	.00	.00
83	90	52	1420.	18.0	.000150	34.64	52.27	344.74	242.77
84	90	91	50.	4.0	.000150	.00	.00	.00	.00
85	77	79	475.	6.0	.000150	.00	.00	.00	.00
86	83	78	240.	18.0	.000150	.00	.00	.00	.00
* 87	90	77	150.	6.0	.000150	.00	.00	.00	.00
88	77	76	140.	6.0	.000150	.00	.00	.00	.00
89	81	80	290.	14.0	.000150	8.64	21.55	17.28	59.58
90	86	83	360.	20.0	.000150	8.64	10.56	3.70	10.27
* 91	85	90	685.	20.0	.000150	34.64	42.34	98.09	143.20
92	83	81	80.	14.0	.000150	8.64	21.55	4.77	59.58
93	85	84	175.	2.0	.000150	.00	.00	.00	.00
94	93	85	360.	20.0	.000150	34.64	42.34	51.55	143.2[illegible]
95	2	93	360.	20.0	.000150	34.64	42.34	51.55	143.20
96	13	34	1150.	12.0	.000150	5.41	18.37	60.57	52.67
97	3	86	360.	24.0	.000150	8.64	7.33	1.51	4.20
99	85	82	50.	4.0	.000150	.00	.00	.00	.00
101	1	75	45.	24.0	.000150	68.97	58.54	9.76	216.87

1PIPE DATA

PIPE NO.	NODES FROM	TO	LENGTH	DIAM	COEF	FLOW RATE	VELOCITY	HEAD LOSS	HLOSS /1000
102	3	6	135.	12.0	.000150	12.14	41.23	33.18	245.77
103	75	5	525.	8.0	.000150	18.98	145.03	2384.99	4542.85

1NODE DATA:

NODE NO.	DEMAND (wt/s)	vol/s	ELEV	HEAD	PRESSURE	HGL ELEV
1	-68.968	-183.92	0.	80640.00	210.00	80640.00
2	.000	.00	0.	80575.48	209.83	80575.48
3	.000	.00	0.	80615.23	209.94	80615.23
5	18.984	50.62	0.	78245.25	203.76	78245.25
6	.000	.00	0.	80582.05	209.85	80582.05
7	.000	.00	0.	80513.54	209.67	80513.54
8	.000	.00	0.	80513.54	209.67	80513.54
9	.000	.00	0.	80339.30	209.22	80339.30
10	.047	.13	0.	80222.67	208.91	80222.67
11	.000	.00	0.	80057.47	208.48	80057.47
12	.000	.00	0.	79839.16	207.91	79839.16
13	.000	.00	0.	79780.44	207.76	79780.44
14	2.279	6.08	0.	79677.77	207.49	79677.77
15	.000	.00	0.	79699.09	207.55	79699.09
16	.000	.00	0.	79892.38	208.05	79892.38
17	.000	.00	0.	79757.94	207.70	79757.94
18	.000	.00	0.	79736.72	207.65	79736.72
19	.000	.00	0.	79732.08	207.64	79732.08
20	1.081	2.88	0.	79363.32	206.68	79363.32
21	.298	.79	0.	79685.91	207.52	79685.91
22	.298	.79	0.	79684.65	207.51	79684.65
23	.298	.79	0.	79629.62	207.37	79629.62
24	.000	.00	0.	79719.78	207.60	79719.78
25	.129	.34	0.	79716.87	207.60	79716.87
26	1.521	4.06	0.	79686.44	207.52	79686.44
27	.000	.00	0.	79675.66	207.49	79675.66
28	.000	.00	0.	79678.61	207.50	79678.61
29	.000	.00	0.	79678.61	207.50	79678.61
30	2.279	6.08	0.	79412.46	206.80	79412.46
31	.000	.00	0.	79680.76	207.50	79680.76
32	2.312	6.16	0.	78577.66	204.63	78577.66
33	4.952	13.21	0.	79641.93	207.40	79641.93
34	.000	.00	0.	79719.87	207.60	79719.87
35	.394	1.05	0.	79679.08	207.50	79679.08
36	.238	.63	0.	79773.41	207.74	79773.41
37	.298	.79	0.	79664.47	207.46	79664.47
38	.591	1.58	0.	79658.06	207.44	79658.06
39	1.148	3.06	0.	79654.57	207.43	79654.57
40	.000	.00	0.	79655.17	207.44	79655.17
41	.000	.00	0.	79703.41	207.56	79703.41
42	.000	.00	0.	79659.90	207.45	79659.90
43	.000	.00	0.	79663.73	207.46	79663.73
44	.000	.00	0.	79669.24	207.47	79669.24
45	.000	.00	0.	79673.97	207.48	79673.97
46	.000	.00	0.	79676.23	207.49	79676.23
47	.000	.00	0.	79701.99	207.56	79701.99
48	.000	.00	0.	79677.94	207.49	79677.94
49	.000	.00	0.	79680.78	207.50	79680.78

1NODE DATA:

NODE NO.	DEMAND (wt/s)	vol/s	ELEV	HEAD	PRESSURE	HGL ELEV
50	.000	.00	0.	79683.95	207.51	79683.95
51	.000	.00	0.	79702.25	207.56	79702.25
52	.000	.00	0.	80029.54	208.41	80029.54
53	.000	.00	0.	79845.24	207.93	79845.24
54	.238	.63	0.	79781.76	207.76	79781.76
55	.000	.00	0.	79752.65	207.69	79752.65
56	.536	1.43	0.	79707.89	207.57	79707.89
57	.368	.98	0.	79568.59	207.21	79568.59
58	.408	1.09	0.	79529.78	207.11	79529.78
59	.238	.63	0.	79738.91	207.65	79738.91
60	.294	.79	0.	79733.64	207.64	79733.64
61	.000	.00	0.	79728.88	207.63	79728.88
62	.000	.00	0.	79720.85	207.61	79720.85
63	.000	.00	0.	79719.21	207.60	79719.21
64	.000	.00	0.	79716.84	207.60	79716.84
65	.000	.00	0.	79713.05	207.59	79713.05
66	.000	.00	0.	79713.05	207.59	79713.05
67	14.389	38.37	0.	52667.64	137.16	52667.64
68	.758	2.02	0.	44224.63	115.17	44224.63
69	.399	1.06	0.	39105.70	101.84	39105.70
70	.000	.00	0.	38204.55	99.49	38204.55
71	1.528	4.08	0.	37718.74	98.23	37718.74
72	.945	2.52	0.	37168.70	96.79	37168.70
73	.451	1.20	0.	38089.77	99.19	38089.77
74	1.528	4.08	0.	35388.30	92.16	35388.30
75	.000	.00	0.	80630.24	209.97	80630.24
76	.000	.00	0.	80374.28	209.31	80374.28
77	.000	.00	0.	80374.28	209.31	80374.28
78	.000	.00	0.	80610.02	209.92	80610.02
79	.000	.00	0.	80374.28	209.31	80374.28
80	8.639	23.04	0.	80587.98	209.86	80587.98
81	.000	.00	0.	80605.26	209.91	80605.26
82	.000	.00	0.	80472.38	209.56	80472.38
83	.000	.00	0.	80610.02	209.92	80610.02
84	.000	.00	0.	80472.38	209.56	80472.38
85	.000	.00	0.	80472.38	209.56	80472.38
86	.000	.00	0.	80613.72	209.93	80613.72
87	.000	.00	0.	80523.93	209.70	80523.93
88	.197	.53	0.	79789.23	207.78	79789.23
89	.904	2.41	0.	75115.71	195.61	75115.71
90	.000	.00	0.	80374.28	209.31	80374.28
91	.000	.00	0.	80374.28	209.31	80374.28
93	.000	.00	0.	80523.93	209.70	80523.93

HOLSTON AREA B

/

$SPECIF NFLOW= 5,NPGPM= 5,NPRRES=1,GAMMA=0.375,VISC=5.088E-006,NODESP=1,
PEAKF=.000278 $END

PIPES

1	75	3	687.5	24.00	0.00015
2	75	2	1315.0	24.00	0.00015
3	2	6	50.0	10.00	0.00015
4	6	7	350.0	10.00	0.00015
5	7	8	120.0	4.00	0.00015
6	7	9	890.0	10.00	0.00015
7	9	10	195.0	8.00	0.00015
8	10	11	280.0	8.00	0.00015
9	11	12	370.0	8.00	0.00015
10	12	88	1170.0	8.00	0.00015
11	88	13	260.0	8.00	0.00015
12	12	17	240.0	8.00	0.00015
13	18	21	240.0	3.00	0.00015
14	17	22	390.0	4.00	0.00015
15	17	18	80.0	8.00	0.00015
16	18	19	20.0	8.00	0.00015
17	19	24	95.0	8.00	0.00015
18	24	25	65.0	3.00	0.00015
19	19	20	150.0	3.00	0.00015
20	22	23	260.0	3.00	0.00015
21	24	26	280.0	8.00	0.00015
22	26	27	370.0	8.00	0.00015
23	27	28	1010.0	8.00	0.00015
24	28	29	250.0	3.00	0.00015
25	28	35	160.0	8.00	0.00015
26	35	31	160.0	8.00	0.00015
27	31	30	110.0	4.00	0.00015
28	31	32	440.0	4.00	0.00015
29	31	34	100.0	8.00	0.00015
30	34	36	520.0	8.00	0.00015
31	13	16	520.0	8.00	0.00015
32	27	37	240.0	8.00	0.00015
33	37	38	195.0	8.00	0.00015
34	38	39	280.0	8.00	0.00015
35	39	40	370.0	8.00	0.00015
36	40	33	1170.0	8.00	0.00015
37	33	41	260.0	8.00	0.00015
38	40	42	240.0	8.00	0.00015
39	41	59	520.0	8.00	0.00015
40	42	43	195.0	8.00	0.00015
41	43	44	280.0	8.00	0.00015
42	44	45	240.0	8.00	0.00015
43	45	46	115.0	8.00	0.00015
44	46	14	1170.0	8.00	0.00015
45	14	47	260.0	8.00	0.00015
46	46	48	140.0	8.00	0.00015
47	62	47	520.0	8.00	0.00015
48	48	49	235.0	8.00	0.00015
49	49	50	260.0	8.00	0.00015
50	50	15	1245.0	8.00	0.00015
51	15	51	260.0	8.00	0.00015
52	51	65	520.0	8.00	0.00015

EMC ENGINEERS, INC.
PROJ. #_____ PROJECT [illegible]
SHEET NO. [illegible] OF [illegible]
CALCULATED BY_____ DATE_____
CHECKED BY_____ DATE_____
SUBJECT_____

EMC ENGINEERS, INC.
PROJ. #______ PROJECT [illegible]
SHEET NO. [illegible] OF 102
CALCULATED BY______ DATE______
CHECKED BY______ DATE______
SUBJECT ______

53	65	66	195.0	8.00	0.00015
54	64	65	540.0	10.00	0.00015
55	63	64	340.0	10.00	0.00015
56	62	63	235.0	10.00	0.00015
[illegible]	61	62	575.0	12.00	0.00015
[illegible]	60	61	340.0	12.00	0.00015
59	59	60	310.0	12.00	0.00015
60	55	59	570.0	14.00	0.00015
61	55	56	400.0	6.00	0.00015
62	56	57	450.0	4.00	0.00015
63	57	58	420.0	4.00	0.00015
64	51	47	1120.0	12.00	0.00015
65	47	41	1150.0	12.00	0.00015
66	34	41	1150.0	12.00	0.00015
67	36	55	570.0	14.00	0.00015
68	54	36	400.0	18.00	0.00015
69	54	89	850.0	8.00	0.00015
70	89	67	1025.0	6.00	0.00015
71	67	68	595.0	4.00	0.00015
72	68	69	480.0	4.00	0.00015
73	69	70	100.0	4.00	0.00015
74	70	71	170.0	4.00	0.00015
75	71	72	290.0	3.00	0.00015
76	70	73	100.0	2.50	0.00015
77	70	74	585.0	3.00	0.00015
78	53	54	330.0	18.00	0.00015
79	16	53	245.0	18.00	0.00015
80	52	16	565.0	18.00	0.00015
82	93	87	50.0	4.00	0.00015
[illegible]	90	52	1420.0	18.00	0.00015
[illegible]	90	91	50.0	4.00	0.00015
85	77	79	475.0	6.00	0.00015
86	83	78	240.0	18.00	0.00015
87	77	90	150.0	6.00	0.00015
88	77	76	140.0	6.00	0.00015
89	81	80	290.0	14.00	0.00015
90	86	83	360.0	20.00	0.00015
91	90	85	685.0	20.00	0.00015
92	83	81	80.0	14.00	0.00015
93	85	84	175.0	2.00	0.00015
94	93	85	360.0	20.00	0.00015
95	2	93	360.0	20.00	0.00015
96	13	34	1150.0	12.00	0.00015
97	3	86	360.0	24.00	0.00015
99	85	82	50.0	4.00	0.00015
101	1	75	45.0	24.00	0.00015
102	3	6	135.0	12.0	0.00015
103	75	5	525.0	8.0	0.00015

NODES

1	306.	0.0
2	.0	0.0
3	.0	0.0
5	68287.	0.0
6	.0	0.0
7	.0	0.0
8	.0	0.0
9	.0	0.0
10	170.	0.0
11	.0	0.0
12	.0	0.0

EMC ENGINEERS, INC.
PROJ. #______ PROJECT ______
SHEET NO. [illegible] OF 102
CALCULATED BY______ DATE______
CHECKED BY______ DATE______
SUBJECT ______

```
13 .0        0.0
14 8198.   0.0
15 .0   0.0
16 .0   0.0
[illegible] .0   0.0
[illegible] .0  0.0
19  .0  0.0
20 3887.0  0.0
21 1072.0  0.0
22 1072.0  0.0
23 1072.0  0.0
24   .0 0.0
25  465.0  0.0
26  5471.  0.0
27  .0  0.0
28  .0  0.0
29  .0  0.0
30  8198.0  0.0
31  .0  0.0
32  8315.0  0.0
33 17814.  0.0
34 .0  0.0
35 1418.0 0.0
36   856.  0.0
37  1072.0  0.0
38   2127.0  0.0
39  4129.0  0.0
40  .0  0.0
41 [illegible]0  0.0
[illegible] .0  0.0
[illegible] .0  0.0
44  .0  0.0
45  .0  0.0
46  .0  0.0
47 .0  0.0
48  .0  0.0
49  .0  0.0
50  .0  0.0
51  .0  0.0
52  .0  0.0
53  .0  0.0
54  856.0
55  .0 0.0
56  1927.0  0.0
57   1325.0  0.0
58   1468.0  0.0
59   856.0  0.0
60  1059.0  0.0
61  0.0  0.0
62   .0  0.0
63  .0  0.0
64  .0  0.0
65  .0  0.0
66  .0  0.0
67 [illegible]1760.0 0.0
[illegible]  2727.0  0.0
69   1434.0  0.0
70   .0 0.0
71   5497.0  0.0
72   3398.0  0.0
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73    1623.0   0.0
74    5497.0   0.0
75    .0   0.0
76   .0   0.0
7   .0   0.0
7_   .0   0.0
79    .0   0.0
80    31077.0   0.0
81    .0   0.0
82    .0   0.0
83    .0   0.0
84    .0   0.0
85    .0   0.0
86   .0   0.0
87    .0   0.0
88 709.0   0.0
89    3252.0   0.0
90   .0 0.0
91    .0   0.0
93   .0   0.0
RESER
1 210
RUN
```

EMC ENGINEERS, INC.
PROJ. #______ PROJECT [illegible]
SHEET NO. 40 OF 10[illegible]
CALCULATED BY______ DATE__________
CHECKED BY________ DATE__________
SUBJECT ____________________

0TITLE GIVEN TO NETWORK

STON AREA B
0ALL DEMAND FLOWS ARE MULTIPLIED BY .0003
0PIPES 101
NODES 91
SOURCE PUMPS 0
BOOSTER PUMPS 0
RESERVOIRS 1
MINOR LOSSES 0
PRVS 0
NOZZLES 0
CHECK VALVE 0
BACK PRES. V. 0
DIF. HEAD DEV 0
SPECIFIED PRES 0

EMC ENGINEERS, INC.
PROJ. #____ PROJECT [illegible]
SHEET NO. 41 OF 102
CALCULATED BY____ DATE____
CHECKED BY____ DATE____
SUBJECT____

100 [illegible] FLOW MODEL
WITH PIPE TO ADMIN AREA

DEMANDS AT PUMP OR RES. NODES NOT AL. FOR PUMP OR RES. 1 AT NODE 1
A D. .085 WAS GIVEN. WILL BE SET TO 0.
TO GIVE EST. OF INFLOW SET NPERCT=1
RES.(NOZZLE) PIPES & THEIR ELEV. ARE
101 82758.6
N9= 101 N8= 90
0JUNCTION EXT. FLOW PIPES AT JUNCTION

1	2	.000	-2	3	95	
2	3	.000	-1	97	102	
3	5	18.984	-103			
4	6	.000	-3	4	-102	
5	7	.000	-4	5	6	
6	8	.000	-5			
7	9	.000	-6	7		
8	10	.047	-7	8		
9	11	.000	-8	9		
10	12	.000	-9	10	12	
11	13	.000	-11	31	96	
12	14	2.279	-44	45		
13	15	.000	-50	51		
14	16	.000	-31	79	-80	104
15	17	.000	-12	14	15	
16	18	.000	13	-15	16	
17	19	.000	-16	17	19	
18	20	1.081	-19			
19	21	.298	-13			
20	22	.298	-14	20		
21	23	.298	-20			
22	24	.000	-17	18	21	
23	25	.129	-18			
24	26	1.521	-21	22		
25	27	.000	-22	23	32	
26	28	.000	-23	24	25	
27	29	.000	-24			
28	30	2.279	-27			
29	31	.000	-26	27	28	29
[illegible]	32	2.312	-28			
31	33	4.952	-36	37		
32	34	.000	-29	30	66	-96
33	35	.394	-25	26		
34	36	.238	-30	67	-68	

EMC ENGINEERS, INC.
PROJ. #______ PROJECT ____________
SHEET NO. ______ OF ______
CALCULATED BY______ DATE__________
CHECKED BY________ DATE__________
SUBJECT ______________________

35	37	.298	-32	33			
36	38	.591	-33	34			
37	39	1.148	-34	35			
38	40	.000	-35	36	38		
39	41	.000	-37	39	-65	-66	
40	42	.000	-38	40			
41	43	.000	-40	41			
42	44	.000	-41	42			
43	45	.000	-42	43			
44	46	.000	-43	44	46		
45	47	.000	-45	-47	-64	65	
46	48	.000	-46	48			
47	49	.000	-48	49			
48	50	.000	-49	50			
49	51	.000	-51	52	64		
50	52	.000	80	-83			
51	53	.000	78	-79			
52	54	.238	68	69	-78		
53	55	.000	60	61	-67		
54	56	.536	-61	62			
55	57	.368	-62	63			
56	58	.408	-63				
57	59	.238	-39	59	-60		
58	60	.294	58	-59			
59	61	.000	57	-58			
60	62	.000	47	56	-57		
61	63	.000	55	-56			
62	64	.000	54	-55			
63	65	.000	-52	53	-54		
64	66	.000	-53				
65	67	14.389	-70	71			
66	68	.758	-71	72			
67	69	.399	-72	73			
68	70	.000	-73	74	76	77	-104
69	71	1.528	-74	75			
70	72	.945	-75				
71	73	.451	-76				
72	74	1.528	-77				
73	75	.000	1	2	-101	103	
74	76	.000	-88				
75	77	.000	85	87	88		
76	78	.000	-86				
77	79	.000	-85				
78	80	8.639	-89				
79	81	.000	89	-92			
80	82	.000	-99				
81	83	.000	86	-90	92		
82	84	.000	-93				
83	85	.000	-91	93	-94	99	
84	86	.000	90	-97			
85	87	.000	-82				
86	88	.197	-10	11			
87	89	.904	-69	70			
88	90	.000	83	84	-87	91	
89	91	.000	-84				
90	93	.000	82	94	-95		

FLOW FROM PUMPS AND RESERVOIRS EQUALS 68.968

ITERATION= 1 SUM= .458E+02
ITERATION= 2 SUM= .151E+02

```
ITERATION=    3 SUM=  .920E+01
ITERATION=    4 SUM=  .329E+01
ITERATION=    5 SUM=  .561E+00
ITERATION=    6 SUM=  .123E-01
ITERATION=    7 SUM=  .659E-05
UNITS OF SOLUTION ARE
DIAMETERS -  inch
LENGTH -  feet
HEADS -  feet
ELEVATIONS -  feet
PRESSURES -  (psi)
FLOWRATES -  (wt/s)
 DARCY-WEISBACH FORMULA USED FOR COMPUTING HEAD LOSS
1PIPE DATA
```

EMC ENGINEERS, INC.
PROJ. #_____ PROJECT 3/??-00?
SHEET NO. ____ OF ____
CALCULATED BY_____ DATE_____
CHECKED BY_____ DATE_____
SUBJECT __________

	PIPE NO.	NODES FROM	TO	LENGTH	DIAM	COEF	FLOW RATE	VELOCITY	HEAD LOSS	HLOSS /1000
	1	75	3	688.	24.0	.000150	20.79	38.03	88.95	129.38
	2	75	2	1315.	24.0	.000150	29.19	53.41	318.34	242.08
*	3	6	2	50.	10.0	.000150	5.58	58.80	40.38	807.67
	4	6	7	350.	10.0	.000150	6.57	69.23	382.01	1091.45
	5	7	8	120.	4.0	.000150	.00	.00	.00	.00
	6	7	9	890.	10.0	.000150	6.57	69.23	971.39	1091.45
	7	9	10	195.	8.0	.000150	6.57	108.17	632.47	3243.42
	8	10	11	280.	8.0	.000150	6.52	107.39	896.06	3200.21
	9	11	12	370.	8.0	.000150	6.52	107.39	1184.08	3200.21
	10	12	88	1170.	8.0	.000150	1.63	26.82	292.68	250.15
	11	88	13	260.	8.0	.000150	1.43	23.58	51.45	197.89
	12	12	17	240.	8.0	.000150	4.89	80.57	450.93	1878.89
	13	18	21	240.	3.0	.000150	.30	34.89	313.88	1307.84
	14	17	22	390.	4.0	.000150	.60	39.25	446.81	1145.67
	15	17	18	80.	8.0	.000150	4.30	70.76	118.26	1478.23
	16	18	19	20.	8.0	.000150	4.00	65.85	25.90	1294.79
	17	19	24	95.	8.0	.000150	2.92	48.06	68.94	725.73
	18	24	25	65.	3.0	.000150	.13	15.13	18.92	291.08
	19	19	20	150.	3.0	.000150	1.08	126.51	2075.89	13839.27
	20	22	23	260.	3.0	.000150	.30	34.89	340.04	1307.84
	21	24	26	280.	8.0	.000150	2.79	45.93	187.01	667.90
	22	26	27	370.	8.0	.000150	1.27	20.89	58.79	158.88
*	23	28	27	1010.	8.0	.000150	.43	7.03	22.59	22.37
	24	28	29	250.	3.0	.000150	.00	.00	.00	.00
*	25	35	28	160.	8.0	.000150	.43	7.03	3.58	22.37
*	26	31	35	160.	8.0	.000150	.82	13.52	11.58	72.36
	27	31	30	110.	4.0	.000150	2.28	150.09	1486.58	13514.36
	28	31	32	440.	4.0	.000150	2.31	152.23	6105.47	13876.06
*	29	34	31	100.	8.0	.000150	5.41	89.10	226.35	2263.46
*	30	36	34	520.	8.0	.000150	2.96	48.80	388.09	746.32
*	31	16	13	520.	8.0	.000150	3.47	57.05	517.10	994.43
	32	27	37	240.	8.0	.000150	1.70	27.92	64.59	269.11
	33	37	38	195.	8.0	.000150	1.40	23.02	36.93	189.40
	34	38	39	280.	8.0	.000150	.81	13.28	19.61	70.04
*	35	40	39	370.	8.0	.000150	.34	5.62	5.55	14.99
	36	40	33	1170.	8.0	.000150	.76	12.47	73.15	62.52
*	37	41	33	260.	8.0	.000150	4.19	69.07	367.57	1413.74
	38	42	40	240.	8.0	.000150	1.10	18.09	29.37	122.38
	39	59	41	520.	8.0	.000150	2.31	38.04	245.99	473.06
*	40	43	42	195.	8.0	.000150	1.10	18.09	23.86	122.38
*	41	44	43	280.	8.0	.000150	1.10	18.09	34.27	122.38
*	42	45	44	240.	8.0	.000150	1.10	18.09	29.37	122.38

*	43	46	45	115.	8.0	.000150	1.10	18.09	14.07	122.38
*	44	14	46	1170.	8.0	.000150	.26	4.32	10.99	9.39
*	45	47	14	260.	8.0	.000150	2.54	41.84	146.40	563.08
*	46	48	46	140.	8.0	.000150	.84	13.77	10.46	74.[illegible]
	47	62	47	520.	8.0	.000150	1.62	26.75	129.46	248.9[illegible]
	48	49	48	235.	8.0	.000150	.84	13.77	17.56	74.74

1PIPE DATA

	PIPE NO.	NODES FROM	TO	LENGTH	DIAM	COEF	FLOW RATE	VELOCITY	HEAD LOSS	HLOSS /1000
*	49	50	49	260.	8.0	.000150	.84	13.77	19.43	74.74
*	50	15	50	1245.	8.0	.000150	.84	13.77	93.05	74.74
*	51	51	15	260.	8.0	.000150	.84	13.77	19.43	74.74
*	52	65	51	520.	8.0	.000150	1.19	19.55	73.28	140.91
	53	65	66	195.	8.0	.000150	.00	.00	.00	.00
	54	64	65	540.	10.0	.000150	1.19	12.51	25.98	48.11
	55	63	64	340.	10.0	.000150	1.19	12.51	16.36	48.11
	56	62	63	235.	10.0	.000150	1.19	12.51	11.31	48.11
	57	61	62	575.	12.0	.000150	2.81	20.58	54.80	95.30
	58	60	61	340.	12.0	.000150	2.81	20.58	32.40	95.30
	59	59	60	310.	12.0	.000150	3.11	22.73	35.41	114.23
	60	55	59	570.	14.0	.000150	5.66	30.40	92.21	161.77
	61	55	56	400.	6.0	.000150	1.31	38.41	271.18	677.95
	62	56	57	450.	4.0	.000150	.78	51.14	834.81	1855.13
	63	57	58	420.	4.0	.000150	.41	26.88	242.11	576.45
	64	51	47	1120.	12.0	.000150	.35	2.57	2.55	2.27
*	65	41	47	1150.	12.0	.000150	.57	4.14	6.08	5.29
	66	34	41	1150.	12.0	.000150	2.45	17.92	85.26	74.1[illegible]
	67	36	55	570.	14.0	.000150	6.97	37.46	135.14	237.0[illegible]
	68	54	36	400.	18.0	.000150	10.17	33.07	56.12	140.31
	69	54	89	850.	8.0	.000150	12.97	213.46	9827.18	11561.39
	70	89	67	1025.	6.0	.000150	12.06	353.02	42994.12	41945.48
*	71	68	67	595.	4.0	.000150	2.33	153.33	8367.86	14063.63
*	72	69	68	480.	4.0	.000150	3.09	203.26	11435.67	23824.31
*	73	70	69	100.	4.0	.000150	3.49	229.51	2993.08	29930.77
	74	70	71	170.	4.0	.000150	2.47	162.85	2675.11	15735.97
	75	71	72	290.	3.0	.000150	.94	110.60	3128.91	10789.33
	76	70	73	100.	2.5	.000150	.45	76.07	673.54	6735.44
	77	70	74	585.	3.0	.000150	1.53	178.92	15431.03	26377.83
	78	53	54	330.	18.0	.000150	23.37	76.01	214.93	651.30
	79	16	53	245.	18.0	.000150	23.37	76.01	159.57	651.30
	80	52	16	565.	18.0	.000150	34.78	113.10	770.78	1364.22
	82	93	87	50.	4.0	.000150	.00	.00	.00	.00
	83	90	52	1420.	18.0	.000150	34.78	113.10	1937.19	1364.22
	84	90	91	50.	4.0	.000150	.00	.00	.00	.00
	85	77	79	475.	6.0	.000150	.00	.00	.00	.00
	86	83	78	240.	18.0	.000150	.00	.00	.00	.00
*	87	90	77	150.	6.0	.000150	.00	.00	.00	.00
	88	77	76	140.	6.0	.000150	.00	.00	.00	.00
	89	81	80	290.	14.0	.000150	8.64	46.45	102.07	351.98
	90	86	83	360.	20.0	.000150	8.64	22.76	22.50	62.49
*	91	85	90	685.	20.0	.000150	34.78	91.61	558.08	814.72
	92	83	81	80.	14.0	.000150	8.64	46.45	28.16	351.9[illegible]
	93	85	84	175.	2.0	.000150	.00	.00	.00	.0[illegible]
	94	93	85	360.	20.0	.000150	34.78	91.61	293.30	814.72
	95	2	93	360.	20.0	.000150	34.78	91.61	293.30	814.72
	96	13	34	1150.	12.0	.000150	4.90	35.84	301.61	262.27
	97	3	86	360.	24.0	.000150	8.64	15.80	9.32	25.89
	99	85	82	50.	4.0	.000150	.00	.00	.00	.00

101	1	75	45.	24.0	.000150	68.97	126.17	53.91	1198.03

1PIPE DATA

PIPE NO.	NODES FROM	TO	LENGTH	DIAM	COEF	FLOW RATE	VELOCITY	HEAD LOSS	HLOSS /1000
102	3	6	135.	12.0	.000150	12.15	88.91	189.00	1400.03
103	75	5	525.	8.0	.000150	18.98	312.55	12479.29	23770.08
104	16	70	1600.	6.0	.000150	7.94	232.32	30399.19	18999.50

1NODE DATA:

NODE NO.	DEMAND (wt/s)	vol/s	ELEV	HEAD	PRESSURE	HGL ELEV
1	-68.968	-396.37	0.	82758.63	100.00	82758.63
2	.000	.00	0.	82386.38	99.55	82386.38
3	.000	.00	0.	82615.76	99.83	82615.76
5	18.984	109.10	0.	70225.42	84.86	70225.42
6	.000	.00	0.	82426.76	99.60	82426.76
7	.000	.00	0.	82044.75	99.14	82044.75
8	.000	.00	0.	82044.75	99.14	82044.75
9	.000	.00	0.	81073.36	97.96	81073.36
10	.047	.27	0.	80440.89	97.20	80440.89
11	.000	.00	0.	79544.83	96.12	79544.83
12	.000	.00	0.	78360.75	94.69	78360.75
13	.000	.00	0.	78016.63	94.27	78016.63
14	2.279	13.10	0.	77477.27	93.62	77477.27
15	.000	.00	0.	77606.79	93.77	77606.79
16	.000	.00	0.	78533.73	94.89	78533.73
17	.000	.00	0.	77909.81	94.14	77909.81
18	.000	.00	0.	77791.55	94.00	77791.55
19	.000	.00	0.	77765.66	93.97	77765.66
20	1.081	6.21	0.	75689.77	91.46	75689.77
21	.298	1.71	0.	77477.67	93.62	77477.67
22	.298	1.71	0.	77463.00	93.60	77463.00
23	.298	1.71	0.	77122.96	93.19	77122.96
24	.000	.00	0.	77696.71	93.88	77696.71
25	.129	.74	0.	77677.79	93.86	77677.79
26	1.521	8.74	0.	77509.70	93.66	77509.70
27	.000	.00	0.	77450.93	93.59	77450.93
28	.000	.00	0.	77473.52	93.61	77473.52
29	.000	.00	0.	77473.52	93.61	77473.52
30	2.279	13.10	0.	76002.09	91.84	76002.09
31	.000	.00	0.	77488.67	93.63	77488.67
32	2.312	13.28	0.	71383.20	86.25	71383.20
33	4.952	28.46	0.	77262.19	93.36	77262.19
34	.000	.00	0.	77715.02	93.91	77715.02
35	.394	2.27	0.	77477.09	93.62	77477.09
36	.238	1.37	0.	78103.10	94.37	78103.10
37	.298	1.71	0.	77386.34	93.51	77386.34
38	.591	3.40	0.	77349.40	93.46	77349.40
39	1.148	6.60	0.	77329.79	93.44	77329.79
40	.000	.00	0.	77335.34	93.45	77335.34
41	.000	.00	0.	77629.76	93.80	77629.76
42	.000	.00	0.	77364.71	93.48	77364.71
43	.000	.00	0.	77388.58	93.51	77388.58
44	.000	.00	0.	77422.84	93.55	77422.84
45	.000	.00	0.	77452.21	93.59	77452.21
46	.000	.00	0.	77466.28	93.61	77466.28
47	.000	.00	0.	77623.67	93.80	77623.67

48	.000	.00	0.	77476.74	93.62	77476.74
49	.000	.00	0.	77494.31	93.64	77494.31

1NODE DATA:

ᐩDE ᑐ.	DEMAND (wt/s)	vol/s	ELEV	HEAD	PRESSURE	HGL ELEV
50	.000	.00	0.	77513.74	93.66	77513.74
51	.000	.00	0.	77626.22	93.80	77626.22
52	.000	.00	0.	79304.51	95.83	79304.51
53	.000	.00	0.	78374.16	94.70	78374.16
54	.238	1.37	0.	78159.23	94.44	78159.23
55	.000	.00	0.	77967.96	94.21	77967.96
56	.536	3.08	0.	77696.78	93.88	77696.78
57	.368	2.12	0.	76861.97	92.87	76861.97
58	.408	2.35	0.	76619.86	92.58	76619.86
59	.238	1.37	0.	77875.75	94.10	77875.75
60	.294	1.69	0.	77840.34	94.06	77840.34
61	.000	.00	0.	77807.94	94.02	77807.94
62	.000	.00	0.	77753.13	93.95	77753.13
63	.000	.00	0.	77741.83	93.94	77741.83
64	.000	.00	0.	77725.47	93.92	77725.47
65	.000	.00	0.	77699.49	93.89	77699.49
66	.000	.00	0.	77699.49	93.89	77699.49
67	14.389	82.70	0.	25337.92	30.62	25337.92
68	.758	4.36	0.	33705.78	40.73	33705.78
69	.399	2.29	0.	45141.45	54.55	45141.45
70	.000	.00	0.	48134.53	58.16	48134.53
71	1.528	8.78	0.	45459.42	54.93	45459.42
72	.945	5.43	0.	42330.51	51.15	42330.51
73	.451	2.59	0.	47460.99	57.35	47460.99
74	1.528	8.78	0.	32703.50	39.52	32703.50
75	.000	.00	0.	82704.71	99.93	82704.71
76	.000	.00	0.	81241.70	98.17	81241.70
77	.000	.00	0.	81241.70	98.17	81241.70
78	.000	.00	0.	82583.94	99.79	82583.94
79	.000	.00	0.	81241.70	98.17	81241.70
80	8.639	49.65	0.	82453.71	99.63	82453.71
81	.000	.00	0.	82555.78	99.75	82555.78
82	.000	.00	0.	81799.78	98.84	81799.78
83	.000	.00	0.	82583.94	99.79	82583.94
84	.000	.00	0.	81799.78	98.84	81799.78
85	.000	.00	0.	81799.78	98.84	81799.78
86	.000	.00	0.	82606.44	99.82	82606.44
87	.000	.00	0.	82093.08	99.20	82093.08
88	.197	1.13	0.	78068.07	94.33	78068.07
89	.904	5.20	0.	68332.05	82.57	68332.05
90	.000	.00	0.	81241.70	98.17	81241.70
91	.000	.00	0.	81241.70	98.17	81241.70
93	.000	.00	0.	82093.08	99.20	82093.08

HOLSTON AREA B

$SPECIF NFLOW= 5,NPGPM= 5,NPRRES=1,GAMMA=0.174,VISC=6.578E-005,NODESP=1,
PEAKF=.000278 $END

PIPES

1	75	3	687.5	24.00	0.00015
2	75	2	1315.0	24.00	0.00015
3	2	6	50.0	10.00	0.00015
4	6	7	350.0	10.00	0.00015
5	7	8	120.0	4.00	0.00015
6	7	9	890.0	10.00	0.00015
7	9	10	195.0	8.00	0.00015
8	10	11	280.0	8.00	0.00015
9	11	12	370.0	8.00	0.00015
10	12	88	1170.0	8.00	0.00015
11	88	13	260.0	8.00	0.00015
12	12	17	240.0	8.00	0.00015
13	18	21	240.0	3.00	0.00015
14	17	22	390.0	4.00	0.00015
15	17	18	80.0	8.00	0.00015
16	18	19	20.0	8.00	0.00015
17	19	24	95.0	8.00	0.00015
18	24	25	65.0	3.00	0.00015
19	19	20	150.0	3.00	0.00015
20	22	23	260.0	3.00	0.00015
21	24	26	280.0	8.00	0.00015
22	26	27	370.0	8.00	0.00015
23	27	28	1010.0	8.00	0.00015
24	28	29	250.0	3.00	0.00015
25	28	35	160.0	8.00	0.00015
26	35	31	160.0	8.00	0.00015
27	31	30	110.0	4.00	0.00015
28	31	32	440.0	4.00	0.00015
29	31	34	100.0	8.00	0.00015
30	34	36	520.0	8.00	0.00015
31	13	16	520.0	8.00	0.00015
32	27	37	240.0	8.00	0.00015
33	37	38	195.0	8.00	0.00015
34	38	39	280.0	8.00	0.00015
35	39	40	370.0	8.00	0.00015
36	40	33	1170.0	8.00	0.00015
37	33	41	260.0	8.00	0.00015
38	40	42	240.0	8.00	0.00015
39	41	59	520.0	8.00	0.00015
40	42	43	195.0	8.00	0.00015
41	43	44	280.0	8.00	0.00015
42	44	45	240.0	8.00	0.00015
43	45	46	115.0	8.00	0.00015
44	46	14	1170.0	8.00	0.00015
45	14	47	260.0	8.00	0.00015
46	46	48	140.0	8.00	0.00015
47	62	47	520.0	8.00	0.00015
48	48	49	235.0	8.00	0.00015
49	49	50	260.0	8.00	0.00015
50	50	15	1245.0	8.00	0.00015
51	15	51	260.0	8.00	0.00015
52	51	65	520.0	8.00	0.00015

EMC ENGINEERS, INC.
PROJ. #______ PROJECT 3/0[illegible]
SHEET NO. 62 OF 102
CALCULATED BY______ DATE______
CHECKED BY______ DATE______
SUBJECT ______

EMC ENGINEERS, INC.

PROJ. #______ PROJECT ______________

SHEET NO. ______ OF 102

CALCULATED BY______ DATE__________

CHECKED BY________ DATE___________

SUBJECT ______________________________

53	65	66	195.0	8.00	0.00015
54	64	65	540.0	10.00	0.00015
55	63	64	340.0	10.00	0.00015
56	62	63	235.0	10.00	0.00015
	61	62	575.0	12.00	0.00015
[illegible]	60	61	340.0	12.00	0.00015
59	59	60	310.0	12.00	0.00015
60	55	59	570.0	14.00	0.00015
61	55	56	400.0	6.00	0.00015
62	56	57	450.0	4.00	0.00015
63	57	58	420.0	4.00	0.00015
64	51	47	1120.0	12.00	0.00015
65	47	41	1150.0	12.00	0.00015
66	34	41	1150.0	12.00	0.00015
67	36	55	570.0	14.00	0.00015
68	54	36	400.0	18.00	0.00015
69	54	89	850.0	8.00	0.00015
70	89	67	1025.0	6.00	0.00015
71	67	68	595.0	4.00	0.00015
72	68	69	480.0	4.00	0.00015
73	69	70	100.0	4.00	0.00015
74	70	71	170.0	4.00	0.00015
75	71	72	290.0	3.00	0.00015
76	70	73	100.0	2.50	0.00015
77	70	74	585.0	3.00	0.00015
78	53	54	330.0	18.00	0.00015
79	16	53	245.0	18.00	0.00015
80	52	16	565.0	18.00	0.00015
82	93	87	50.0	4.00	0.00015
83	90	52	1420.0	18.00	0.00015
	90	91	50.0	4.00	0.00015
85	77	79	475.0	6.00	0.00015
86	83	78	240.0	18.00	0.00015
87	77	90	150.0	6.00	0.00015
88	77	76	140.0	6.00	0.00015
89	81	80	290.0	14.00	0.00015
90	86	83	360.0	20.00	0.00015
91	90	85	685.0	20.00	0.00015
92	83	81	80.0	14.00	0.00015
93	85	84	175.0	2.00	0.00015
94	93	85	360.0	20.00	0.00015
95	2	93	360.0	20.00	0.00015
96	13	34	1150.0	12.00	0.00015
97	3	86	360.0	24.00	0.00015
99	85	82	50.0	4.00	0.00015
101	1	75	45.0	24.00	0.00015
102	3	6	135.0	12.0	0.00015
103	75	5	525.0	8.0	0.00015
104	16	70	1600.0	6.0	0.00015

NODES

1	306.	0.0
2	.0	0.0
3	.0	0.0
5	68287.	0.0
6	.0	0.0
[illegible]	0	0.0
8	.0	0.0
9	.0	0.0
10	170.	0.0
11	.0	0.0

12	.0	0.0
13	.0	0.0
14	8198.	0.0
15	[illegible]0	0.0
[illegible]	.0	0.0
1[illegible]	.0	0.0
18	.0	0.0
19	.0	0.0
20	3887.0	0.0
21	1072.0	0.0
22	1072.0	0.0
23	1072.0	0.0
24	.0	0.0
25	465.0	0.0
26	5471.	0.0
27	.0	0.0
28	.0	0.0
29	.0	0.0
30	8198.0	0.0
31	.0	0.0
32	8315.0	0.0
33	17814.	0.0
34	.0	0.0
35	1418.0	0.0
36	856.	0.0
37	1072.0	0.0
38	2127.0	0.0
39	4129.0	0.0
40	.0	0.0
4[illegible]	[illegible]0	0.0
[illegible]	.0	0.0
43	.0	0.0
44	.0	0.0
45	.0	0.0
46	.0	0.0
47	.0	0.0
48	.0	0.0
49	.0	0.0
50	.0	0.0
51	.0	0.0
52	.0	0.0
53	.0	0.0
54	856.0	
55	.0	0.0
56	1927.0	0.0
57	1325.0	0.0
58	1468.0	0.0
59	856.0	0.0
60	1059.0	0.0
61	0.0	0.0
62	.0	0.0
63	.0	0.0
64	.0	0.0
65	.0	0.0
66	.0	0.0
[illegible]	[illegible]1760.0	0.0
6[illegible]	2727.0	0.0
69	1434.0	0.0
70	.0	0.0
71	5497.0	0.0

EMC ENGINEERS, INC.
PROJ. #______ PROJECT 3102-0[illegible]
SHEET NO. 69 OF 102
CALCULATED BY______ DATE______
CHECKED BY______ DATE______
SUBJECT______

```
72    3398.0   0.0
73    1623.0   0.0
74    5497.0   0.0
75    .0   0.0
     .0   0.0
     .0   0.0
78   .0   0.0
79    .0   0.0
80    31077.0   0.0
81    .0   0.0
82    .0   0.0
83    .0   0.0
84    .0   0.0
85    .0   0.0
86   .0   0.0
87    .0   0.0
88  709.0   0.0
89    3252.0   0.0
90   .0 0.0
91    .0   0.0
93   .0   0.0
RESER
1 100
RUN
```

EMC ENGINEERS, INC.
PROJ. #______ PROJECT ______
SHEET NO. ______ OF 10
CALCULATED BY______ DATE______
CHECKED BY______ DATE______
SUBJECT ______

PRV FLOW CALCULATION

$$C_v = \frac{w}{500\sqrt{G\Delta p}}.$$

$$w = 500\, C_v \sqrt{G\Delta p}.$$

where

p	G
315 psia	1.47 ft^3/lbm
110	4.05

EMC ENGINEERS, INC.
PROJ. #______ PROJECT ______
SHEET NO. 51 OF 102
CALCULATED BY______ DATE______
CHECKED BY______ DATE______
SUBJECT ______

PRVSTAT.WK3

EMC ENGINEERS, INC.
PROJ. #_____ PROJECT _____
SHEET NO. ____ OF ____
CALCULATED BY ____ DATE ____
CHECKED BY ____ DATE ____
SUBJECT _____

INCLUDED HERE IS INFORMATION ON PRV'S. THE INFORMATION INCLUDES
LOCATION, PRESSURE SETTING, MANUFACUTRE, MODEL NUMBER, CV, AND % OPEN AT TIME OF FIELD SURVEY.
FLOW RATES AT THE EXISTING 300 PSIG AND AT THE NEW 100 PSIG ARE CALCULATED BASED ON CV.
ALSO INCLUDED IS THE AVERAGE FLOW THROUGH THE PRV BASED ON HISTORICAL DATA.

BUILDING NUMBER	VALVE (1 OR 2)	OUTPUT PRESSURE PSI	Cv	SIZE OF VALVE INCHES	AVERAGE FLOW LB/HR	FLOW AT 300PSI LB/HR	FLOW AT 100 PSI LB/HR	FLOW RATIO 100/300	PART COMPANY AND ID	PERCENT OPEN
G3	1	38	125	3	7,808	105,628	63,637	0.60	ITT 500HC33COACK-A41AFD6AB	25
G3	2	25							FISHER CONTROL H-111	
G4	1	38	125	3	7,808	105,628	63,637	0.60	ITT	62.5
G5	1		80	2.5	7,808	72,339	43,581	0.60	ITT	CLOSED
G5	2	100	5.8	1		4,282	2,580	0.60	KECKLEY-AA	
G6	1	47		2.5	7,808				FISHER	25
G6	2	47	22.38	0.75		18,584	11,196	0.60	JAMESBURY	100
G7	1			1.5	7,808				FISHER GOVANER CO SIZE 70	CLOSED
G7	2	15							CASHCO 1000HP-15	
G7	3	40	4.4	0.75		3,704	2,231	0.60	JORDON	
M3	1	3	7	0.75		6,298	3,794	0.60	CASHCO	12.5
M6	1	3	7	0.75		6,298	3,794	0.60	CASHCO	12.5
D3	1	30		2	1,835				VICH-2M2CBOA	
D3	2								FOXBOROUGH-STABLIFLO	31.2
D5	1	7	37	1.5	1,835	33,064	19,920	0.60	HAMMEL DAHL INC	6.25
D5	2	15		4					FISHER	
E3	1	100			235				CASHCO-1000LP-15	
E3	2	95		1.5					KECKLEY TYPE AA	
E3	3	5	22	1.5	816	19,727	11,885	0.60	CASHCO MODEL 964	
E3	4	110		1.5					CASHCO	
E4	1	70		1.5					ITT	12.5
E4	2	100	15	1.5		11,075	6,672	0.60	KECKLEY-AA	
E6	1	100	1.7	0.5	235	1,255	756	0.60	KECKLEY-AA	
E6	2	50	22	1.5	816	18,160	10,941	0.60	CASHCO	CLOSED

EMC ENGINEERS, INC.
PROJ. #______ PROJECT ______
SHEET NO. 5__ OF ______
CALCULATED BY______ DATE________
CHECKED BY________ DATE__________
SUBJECT ________________________

```
A:A11: {Page DUTCH10 LR} 'G3
A:B11: {DUTCH10 R} [W6] 1
A:C11: {DUTCH10 R} 38
A:D11: {DUTCH10 R} [W6] 125
A:E11: {DUTCH10 R} 3
A:F11: {DUTCH10 R} (,0) 7808
A:G11: {DUTCH10 R} (,0) 500*$D11*(1/1.47/62.4*(300-$C11))^0.5
A:H11: {DUTCH10 R} (,0) 500*$D11*(1/4.05/62.4*(300-$C11))^0.5
A:I11: {DUTCH10 R} (F2) @IF(G11>0,H11/G11,0)
A:J11: {DUTCH10} 'ITT 500HC33COACK-A41AFD6AB
A:M11: {DUTCH10 LR} 25
```

D3 INFORMATION

30 lb steam	STABILFLO VI series	5/16 open
2" valve	FOXBOROUGH	process is steady
1.25" stroke	Clear/CV = 60%	using 30–40% of plant

Continuous
2 simmer tanks 80 and 100 C process
Actuator P110CH–J4
Valve VICH–2M2CBOA

D3	PROCESS	

D5 INFORMATION

HMX BATCH	2nd Valve
500HHC32EAEXK–JK251	15psi
1.5 inch	FISHER 4inch
7–18psi	7/16 inch stroke
1/16 open	Type 655–ED
Cv=3A	15 psi Relief 2420 lb/hr

Most BCDGS operating at 50% Capacity
(4) Simmer tanks
(2) Operating
Batch 100C 2hrs twice
Tanks not insulated

D5	PROCESS	
D6	PROCESS	
E1	PROCESS	

E3 INFORMATION

Gage 24psi	Relief Valve – 5435 lb/hr
Little steam use	4752 lb/hr
HTX – Acedic Acid (used little once every 5 days)	KECKLEY STROKE
Filter Washer 90C (Used once week for 1 hr)	1.5 INCH
Space heat	type AA
1st valve – CASHCO, Ellsworth, KS	set 95 psi
Type 1000LP–15 100 lb steam	

PLK Water Head		Primary Valve
CAASCO	STORO .562"	CASHCO 1.5 inch
1.5 inch	1/8–1/4 open	1000HP–15
Model 964		10–40 psi range
Cv=22		110 psi out
5–15 psi PILOT		300 psi in
28psi		

E3	PROCESS	

E4 INFORMATION

PRV = 70psi	2nd PRV
ITT	KECKLY–AA
1.5 inch	1.5 inch
1/8 open	100psi

Relief PRV
23150LBH 150 psig

EMC ENGINEERS, INC.
PROJ. # ______ PROJECT ______
SHEET NO. ______ OF 102
CALCULATED BY ______ DATE ______
CHECKED BY ______ DATE ______
SUBJECT ______

E4	PROCESS	

E6 similar to E3
KECKLY
1/2" Type AA 100psi – 2nd one on other side 3rd on ACSO
CHAGCO
1.5 inch HW Tank
MORE 964 50 psi
Cv=22
Closed

E6	PROCESS	
F3	412,945	
F5	412,945	
G1	PROCESS	

EMC ENGINEERS, INC.
PROJ. #______ PROJECT ______
SHEET NO. ______ OF 102
CALCULATED BY KK DATE ______
CHECKED BY ______ DATE ______
SUBJECT ______

G3 INFORMATION

38 psi steam
ITT CONOFLO
size 3
500LHC33COACK-A41AFD6AB
300psig
1/4 open
All Patch

2nd valve
Fisher Control h-111
25-75 psi

G3	PROCESS	

G4 INFORMATION

38 psi
ITT
3 inch
T=425 F in
5/8 open

G4	PROCESS	

G5 INFORMATION

ITT
2.5 inch
CLOSED
Cv=80

2nd PRV
KECKLEY - AA
1 inch
100psi ?

G5	PROCESS	

G6 INFORMATION

2.5" FISHER
25% open
Type G87?
47 psi

2nd valve
3/4" JAMESBURY
Wide open

G6	PROCESS	

G7 INFORMATION

FISHER GOVANER CO
4,314,804
SIZE 70
1.5" STROKE
CLOSED

2nd valve
RPM - sec
300psi-110psi-15psi
110-15psi
CHASCO 1000HP-15

Little one
Jordon 3/4"
Model 60
Cv = 4.4
40 psi

Disolver (Acetone)
58C
STILLS
38 psi sparger
live steam injection

1	199,458	
H3	199,458	
H4	199,458	
H5	199,458	
H6	199,458	
I3	301,485	
I4	301,485	
I6	301,485	
J3	301,485	
J4	301,485	
J5	301,485	
K3	130,875	
K5	114,340	
L3	301,485	
L4	301,485	
L6	301,485	

M3 INFORMATION

300 psi steam engines operating
Control Valves - same as M ^
3/8 inch orafice
8" Bore
10-12" stroke
300 rpm
125 hp

M3	301,485	
M4	301,485	
M5	301,485	

M6 INFORMATION

35 psi
3/4" CASHCO
Type 964
3-15psi
Cv = 7
1/8 open
Dryers in M-Bldgs
Not oper in M6, But steam still to coil

uses 300 psi steam engines
kettle mixers
in all "M" bldgs

M6	301,485	
3	182,701	
[illegible]	257,280	
5	182,701	
N6	257,280	
O3	76,085	
O5	76,085	
P3	503,540	
R3	29,690	
W1	47,846	
Y1	0	

COGEN SIZE OPTIMIZATION (Model Inputs)

110 PSIG OPTION

EMC ENGINEERS, INC.
PROJ. #______ PROJECT ______
SHEET NO. ______ OF 102
CALCULATED BY ______ DATE ______
CHECKED BY ______ DATE ______
SUBJECT ______

813 kW @ 67,700 lbm/hr » **83.3 lbm/hr/kW**

T/G Cost	$227,600
Support System Cost	146,802
Electric Equipment Cost	30,000
	$404,400

Added Piping to Distribution Area $133,894

$h_1 = 1270$ Btu/lbm (300 psig, 525°F)

$$w = \text{Turbine Work} = \frac{3413 \text{ Btu}}{\text{kWh}} \; \frac{\text{kWh}}{83.3 \text{ lbm} \times 0.9} = 45.5 \frac{\text{Btu}}{\text{lbm}}$$

$h_2 = h_1 - w = 1224$ Btu/lbm

@ 110 psig » **430°F Superheated**

d h Now = 1270 - 242 (30 psig, SAT) = **1028 Btu/lbm**

d h New = 1224 - 242 = **982 Btu/lbm**

175 PSIG OPTION

420 kW @ 65,000 lbh » **155 lbm/hr/kW**

T/G Cost	$186,000
Support System Cost	146,802
Electric Equipment Cost	30,000
	$362,800

$h_1 = 1270$ Btu/lbm

$$w = \frac{3413 \text{ Btu}}{\text{kWh}} \; \frac{\text{kWh}}{155 \text{ lbm} \times 0.9} = 24.5 \frac{\text{Btu}}{\text{lbm}}$$

$h_2 = 1270 - 25 = 1245$

@ 175 psig, **T = 450°F, Superheated**

d h New = 1245 - 242 = **1003 Btu/lbm**

EMC ENGINEERS, INC.
PROJ. #______ PROJECT 3102-007
SHEET NO. 32 OF 103
CALCULATED BY ______ DATE 1/6/92
CHECKED BY ______ DATE 1/7/92
SUBJECT ______

COGENERATION ANALYSIS WITH 110 PSIG BACKPRESSURE

BLC	1,865,000		SPACE LOAD COEF
UA	22,622		DISTRIBUTION LOSS COEF
PROC	106,982	LBM/HR	PROCESS DEMAND
PROC300	47,462	LBM/HR	300 PSIG DEMAND
DHNOW	1,028	BTU/LBM	300 PSIG ENERGY CONTENT
DHNEW	982	BTU/LBM	EXIT STEAM ENERGY CONTENT
INB	16%		IN PLANT STEAM
TSTM	430		STEAM TEMP
ASR	83	LBM/KW/HR	TURBINE STEAM RATE
SIZE	120,000	LBM/HR	TURBINE SIZE
BOILEFF	72.00%		
COAL$	1.2500	$/MBTU	
KW$	9.5000	$/KW	
KWH$	0.0159	$/KWH	

		DEGREE DAYS	AMBIENT TEMP (F)	LOW PRES PROCESS (LBM/HR)	300 psig PROCESS (LBM/HR)	HEATING LOAD (LBM/HR)	DSTRB LOSS (LBM/HR)	STEAM DEMAND (LBM/HR)	COGEN STEAM (LBM/HR)	ELECTRIC USAGE (KWH)	ELECTRIC DEMAND (KW)	AVG DEMAND (KW)	TURBINE STEAM (LBM/HR)
Jan	31	930	35	62,308	47,462	56,976	9,099	175,845	128,383	5,545,500	9,235	7,454	120,000
Feb	28	759	38	62,308	47,462	51,481	9,030	170,282	122,820	4,716,000	8,926	7,018	120,000
Mar	31	580	46	62,308	47,462	35,533	8,846	154,149	106,687	4,619,000	8,793	6,208	106,687
Apr	30	375	56	62,308	47,462	23,740	8,616	142,126	94,664	5,047,000	8,815	7,010	94,664
May	31	111	64	62,308	47,462	6,800	8,431	125,002	77,540	4,513,500	8,650	6,067	77,540
Jun	30	10	72	62,308	47,462	633	8,247	118,650	71,188	4,621,000	8,904	6,418	71,188
Jul	31	0	75	62,308	47,462	0	8,178	117,948	70,486	4,944,500	8,948	6,646	70,486
Aug	31	0	74	62,308	47,462	0	8,201	117,971	70,509	4,618,000	8,992	6,207	70,509
Sep	30	35	69	62,308	47,462	2,216	8,316	120,302	72,840	4,925,000	9,340	6,840	72,840
Oct	31	263	57	62,308	47,462	16,112	8,593	134,475	87,013	4,970,500	8,909	6,681	87,013
Nov	30	564	46	62,308	47,462	35,705	8,846	154,321	106,859	5,012,000	9,045	6,961	106,859
Dec	31	831	38	62,308	47,462	50,910	9,030	169,711	122,249	5,221,500	9,092	7,018	120,000
Yr		4,458	56	62,308	47,462	23,342	8,620	141,732	94,270	58,753,500	8,971	6,711	1,117,787

EMC ENGINEERS, INC.
PROJ. #______ PROJECT ______
SHEET NO. 58 OF 152
CALCULATED BY ______ DATE ______
CHECKED BY ______ DATE ______
SUBJECT ______

COGENERATION ANALYSIS WITH 110 PSIG BACKPRESSURE

ECONOMIC ANALYSIS							
BASE ENERGY COST	4,576,113						
TURBINE SIZE (LBM/HR)	120,000	20,000	40,000	60,000	80,000	100,000	120,000
ANNUAL ENERGY COST	4,395,395	4,493,046	4,449,075	4,405,104	4,378,030	4,380,408	4,395,395
ENERGY COST SAVINGS	180,718	83,067	127,038	171,009	198,083	195,705	180,718
CAPITAL COST	737,601	306,128	413,690	505,519	588,423	665,267	737,601
SIMPLE PAYBACK	4.1	3.7	3.3	3.0	3.0	3.4	4.1

	POWER PRODUCE (KW)	DESUPER STEAM IN (LBM/HR)	CHP DEMAND (LBM/HR)	IN PLANT STEAM (LBM/HR)	BOILER STEAM (LBM/HR)	BOILER STEAM (MBTU)	COAL USAGE (MBTU)	DEMAND BILLED (KW)	ELECTRIC PURCHASE (KWH)	COAL PURCHASE ($)	DEMAND CHARGES ($)	KWH CHARGES ($)	ELECTRIC CHARGES ($)	TOTAL CHARGES ($)
Jan	1,441	8,008	175,470	34,422	209,892	160,532	222,962	7,795	4,473,711	$278,702	$74,049	$70,908	$146,132	$424,834
Feb	1,441	2,694	170,156	33,380	203,536	140,606	195,286	7,485	3,747,933	$244,107	$71,111	$59,405	$131,690	$375,797
Mar	1,113	0	154,149	30,240	184,389	141,027	195,870	7,680	3,790,855	$244,838	$72,962	$60,085	$134,222	$379,060
Apr	853	0	142,126	27,881	170,007	125,832	174,767	7,962	4,432,631	$218,459	$75,641	$70,257	$147,072	$365,530
May	542	0	125,002	24,522	149,524	114,361	158,834	8,108	4,110,105	$198,543	$77,022	$65,145	$143,341	$341,884
Jun	444	0	118,650	23,276	141,926	105,048	145,900	8,459	4,301,026	$182,375	$80,364	$68,171	$149,710	$332,085
Jul	434	0	117,948	23,138	141,086	107,907	149,871	8,514	4,621,468	$187,339	$80,881	$73,250	$155,306	$342,645
Aug	435	0	117,971	23,143	141,114	107,928	149,901	8,558	4,294,720	$187,376	$81,298	$68,071	$150,543	$337,919
Sep	469	0	120,302	23,600	143,902	106,510	147,931	8,871	4,587,376	$184,914	$84,277	$72,710	$158,161	$343,075
Oct	706	0	134,475	26,380	160,856	123,027	170,871	8,204	4,445,424	$213,589	$77,934	$70,460	$149,568	$363,158
Nov	1,117	0	154,321	30,273	184,594	136,629	189,763	7,928	4,207,722	$237,204	$75,312	$66,692	$143,179	$380,383
Dec	1,441	2,148	169,610	33,273	202,883	155,171	215,516	7,651	4,149,711	$269,395	$72,685	$65,773	$139,632	$409,027
Yr			141,682	27,794	169,476	1,524,580	2,117,472		51,162,684	2,646,840	923,537	810,929	1,748,555	4,395,395

EMC ENGINEERS, INC.
PROJ. # ____ PROJECT ____
SHEET NO. 59 OF 102
CALCULATED BY ____ DATE ____
CHECKED BY ____ DATE ____
SUBJECT ____

COGENERA[illegible]N ANALYSIS WITH 175 PSIG BACKPRESSURE

BLC	1,865,000		SPACE LOAD COEF
UA	22,622		DISTRIBUTION LOSS COEF
PROC	106,982	LBM/HR	PROCESS DEMAND
PROC300	47,462	LBM/HR	300 PSIG DEMAND
DHNOW	1,028	BTU/LBM	300 PSIG ENERGY CONTENT
DHNEW	1,003	BTU/LBM	EXIT STEAM ENERGY CONTENT
INB	16%		IN PLANT STEAM
TSTM	450		STEAM TEMP
ASR	155	LBM/KW/HR	TURBINE STEAM RATE
SIZE	120,000	BTU/LBM	TURBINE SIZE
BOILEFF	72.00%		
COAL$	1.2500	$/MBTU	
KW$	9.5000	$/KW	
KWH$	0.0159	$/KWH	

		DEGREE DAYS	AMBIENT TEMP (F)	LOW PRES PROCESS (LBM/HR)	300 psig PROCESS (LBM/HR)	HEATING LOAD (LBM/HR)	DSTRB LOSS (LBM/HR)	STEAM DEMAND (LBM/HR)	COGEN STEAM (LBM/HR)	ELECTRIC USAGE (KWH)	ELECTRIC DEMAND (KW)	AVG DEMAND (KW)	TURBINE STEAM (LBM/HR)
Jan	31	930	35	61,004	47,462	55,783	9,360	173,608	126,146	5,545,500	9,235	7,454	120,000
Feb	28	759	38	61,004	47,462	50,404	9,292	168,162	120,700	4,716,000	8,926	7,018	120,000
Mar	31	580	46	61,004	47,462	34,789	9,112	152,367	104,905	4,619,000	8,793	6,208	104,905
Apr	30	375	56	61,004	47,462	23,243	8,886	140,595	93,133	5,047,000	8,815	7,010	93,133
May	31	111	64	61,004	47,462	6,658	8,706	123,829	76,367	4,513,500	8,650	6,067	76,367
Jun	30	10	72	61,004	47,462	620	8,526	117,611	70,149	4,621,000	8,904	6,418	70,149
Jul	31	0	75	61,004	47,462	0	8,458	116,923	69,461	4,944,500	8,948	6,646	69,461
Aug	31	0	74	61,004	47,462	0	8,480	116,946	69,484	4,618,000	8,992	6,207	69,484
Sep	30	35	69	61,004	47,462	2,169	8,593	119,228	71,766	4,925,000	9,340	6,840	71,766
Oct	31	263	57	61,004	47,462	15,775	8,864	133,104	85,642	4,970,500	8,909	6,681	85,642
Nov	30	564	46	61,004	47,462	34,957	9,112	152,535	105,073	5,012,000	9,045	6,961	105,073
Dec	31	831	38	61,004	47,462	49,844	9,292	167,602	120,140	5,221,500	9,092	7,018	120,000
Yr		4,458	56	61,004	47,462	22,853	8,890	140,209	92,747	58,753,500	8,971	6,711	1,105,980

EMC ENGINEERS, INC.
PROJ. # PROJECT
SHEET NO. 60 OF
CALCULATED BY DATE
CHECKED BY DATE
SUBJECT

COGENERATION ANALYSIS WITH 175 PSIG BACKPRESSURE

ECONOMIC ANALYSIS								
BASE ENERGY COST	4,576,113							
TURBINE SIZE (LBH)	120,000	0	20,000	40,000	60,000	80,000	100,000	120,000
ANNUAL ENERGY COST	4,471,615	4,545,248	4,521,718	4,498,189	4,474,660	4,461,409	4,463,088	4,471,615
ENERGY COST SAVINGS	104,498	30,865	54,395	77,924	101,453	114,704	113,025	104,498
CAPITAL COST	557,256	1	158,982	258,268	343,031	419,557	490,487	557,256
SIMPLE PAYBACK	5.3	0.0	2.9	3.3	3.4	3.7	4.3	5.3

	POWER PRODUCE (KW)	DESUPER STEAM IN (LBM/HR)	CHP DEMAND (LBM/HR)	IN PLANT STEAM (LBM/HR)	BOILER STEAM (LBM/HR)	BOILER STEAM (MBTU)	COAL USAGE (MBTU)	DEMAND BILLED (KW)	ELECTRIC PURCHASE (KWH)	COAL PURCHASE ($)	DEMAND CHARGES ($)	KWH CHARGES ($)	ELECTRIC CHARGES ($)	TOTAL CHARGES ($)
Jan	774	5,997	173,459	34,028	207,487	158,692	220,406	8,461	4,969,500	$275,508	$80,380	$78,767	$160,321	$435,828
Feb	774	683	168,145	32,985	201,130	138,944	192,977	8,152	4,195,742	$241,222	$77,441	$66,503	$145,118	$386,340
Mar	576	0	152,367	29,890	182,257	139,396	193,605	8,217	4,190,202	$242,007	$78,062	$66,415	$145,650	$387,657
Apr	442	0	140,595	27,581	168,176	124,477	172,884	8,373	4,728,679	$216,106	$79,547	$74,950	$155,670	$371,776
May	281	0	123,829	24,292	148,121	113,288	157,344	8,368	4,304,212	$196,680	$79,500	$68,222	$148,896	$345,577
Jun	231	0	117,611	23,072	140,683	104,128	144,622	8,673	4,454,881	$180,778	$82,394	$70,610	$154,178	$334,956
Jul	225	0	116,923	22,937	139,861	106,970	148,569	8,723	4,776,780	$185,712	$82,865	$75,712	$159,751	$345,462
Aug	226	0	116,946	22,942	139,888	106,990	148,598	8,767	4,450,151	$185,747	$83,283	$70,535	$154,992	$340,739
Sep	243	0	119,228	23,389	142,617	105,560	146,611	9,097	4,749,750	$183,263	$86,419	$75,284	$162,877	$346,140
Oct	366	0	133,104	26,111	159,216	121,773	169,130	8,543	4,698,300	$211,412	$81,163	$74,468	$156,805	$368,217
Nov	578	0	152,535	29,923	182,458	135,048	187,567	8,466	4,595,564	$234,458	$80,430	$72,840	$154,444	$388,902
Dec	774	137	167,599	32,878	200,477	153,331	212,960	8,317	4,645,500	$266,200	$79,016	$73,631	$153,821	$420,021
Yr			140,195	27,502	167,697	1,508,597	2,095,274		54,759,261	2,619,092	970,499	867,934	1,852,523	4,471,615

EMC ENGINEERS, INC.
PROJ. #______ PROJECT ____________
SHEET NO. ___1___ OF ___102___
CALCULATED BY ______ DATE ________
CHECKED BY ______ DATE __1/3/92__
SUBJECT ____________

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A:B21: {Page LRT} [W3] 31
A:C21: {LRT} 930
A:D21: {LRT} 35
A:E21: {LRT} ($PROC-$PROC300)*$DHNOW/$DHNEW
A:F21: {LRT} +$PROC300
A:G21: {LRT} +$BLC*C21/B21/$DHNEW
A:H21: {LRT} +$UA*($TSTM-D21)/$DHNEW
A:I21: {LRT} @SUM(E21..H21)
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A:K21: {LRT} 5545500
A:L21: {LRT} 9235.23183594095289
A:M21: {LRT} +K21/B21/24
A:N21: {LRT} @MIN($SIZE,J21)
A:O21: {MPage LRT} +N21/$ASR*(1.18*N21/$SIZE-0.18)
A:P21: {LRT} (J21-N21)*$DHNEW/$DHNOW
A:Q21: {LRT} +$PROC300+(N21+P21)
A:R21: {LRT} +$INB*S21
A:S21: {LRT} +Q21/(1-$INB)
A:T21: {LRT} +S21*24*B21*$DHNOW/1000000
A:U21: {LRT} +T21/$BOILEFF
A:V21: {LRT} +L21-O21
A:W21: {LRT} +K21-O21*24*B21
A:X21: {LRT} (C0) +U21*$COAL$
A:Y21: {LRT} (C0) +V21*$KW$
A:Z21: {LRT} (C0) +W21*$KWH$
A:AA21: {LRT} (C0) +Y21+Z21+1192*0.985
A:AB21: {LRT} (C0) +X21+AA21
A:AC21: {MPage LRT} (F1) +$PROC*$B21*24/1000000
A:AD21: {LRT} (F1) +H21*$B21*24/1000000
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A:AF21: {LRT} (F1) @SUM(AC21..AE21)
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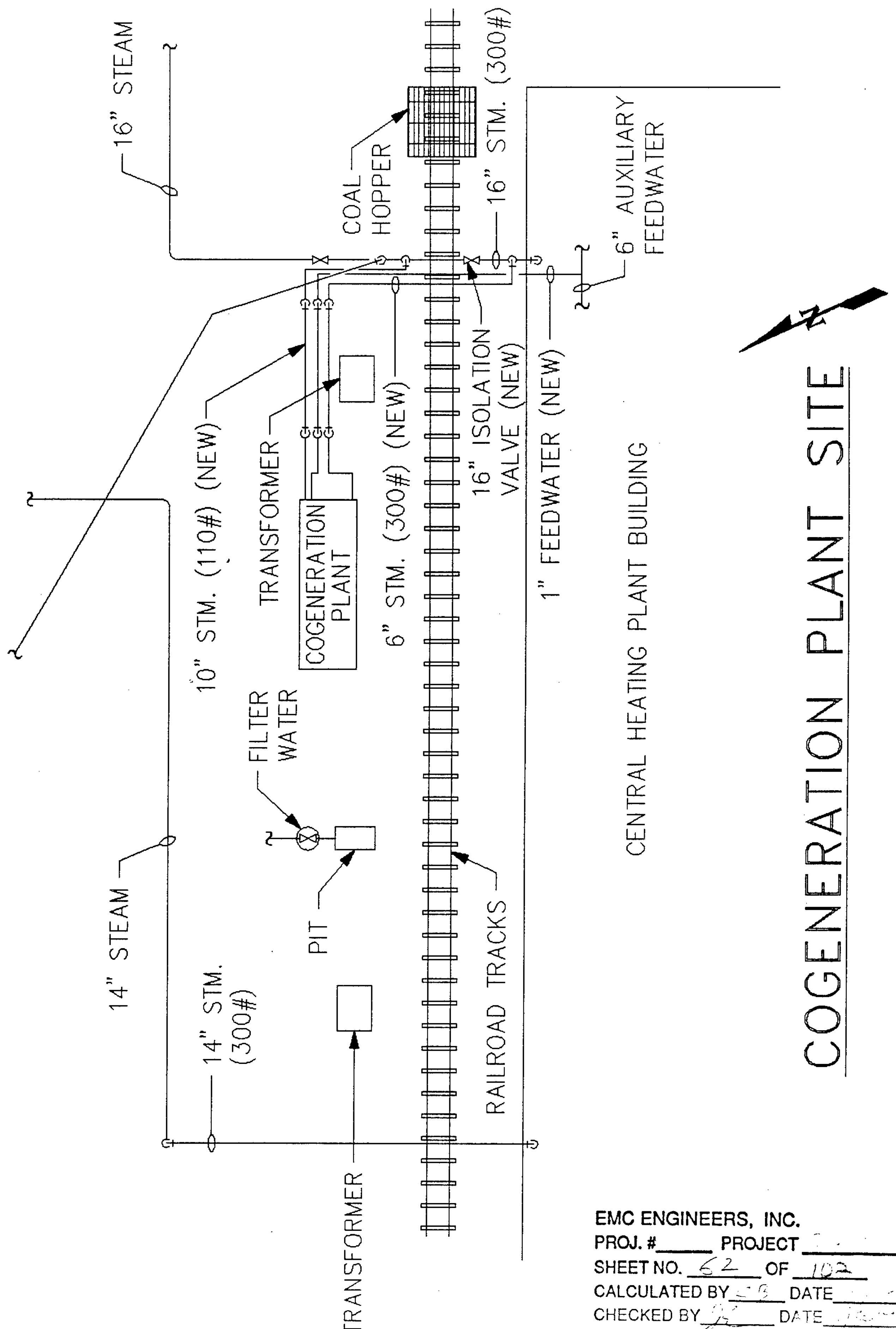
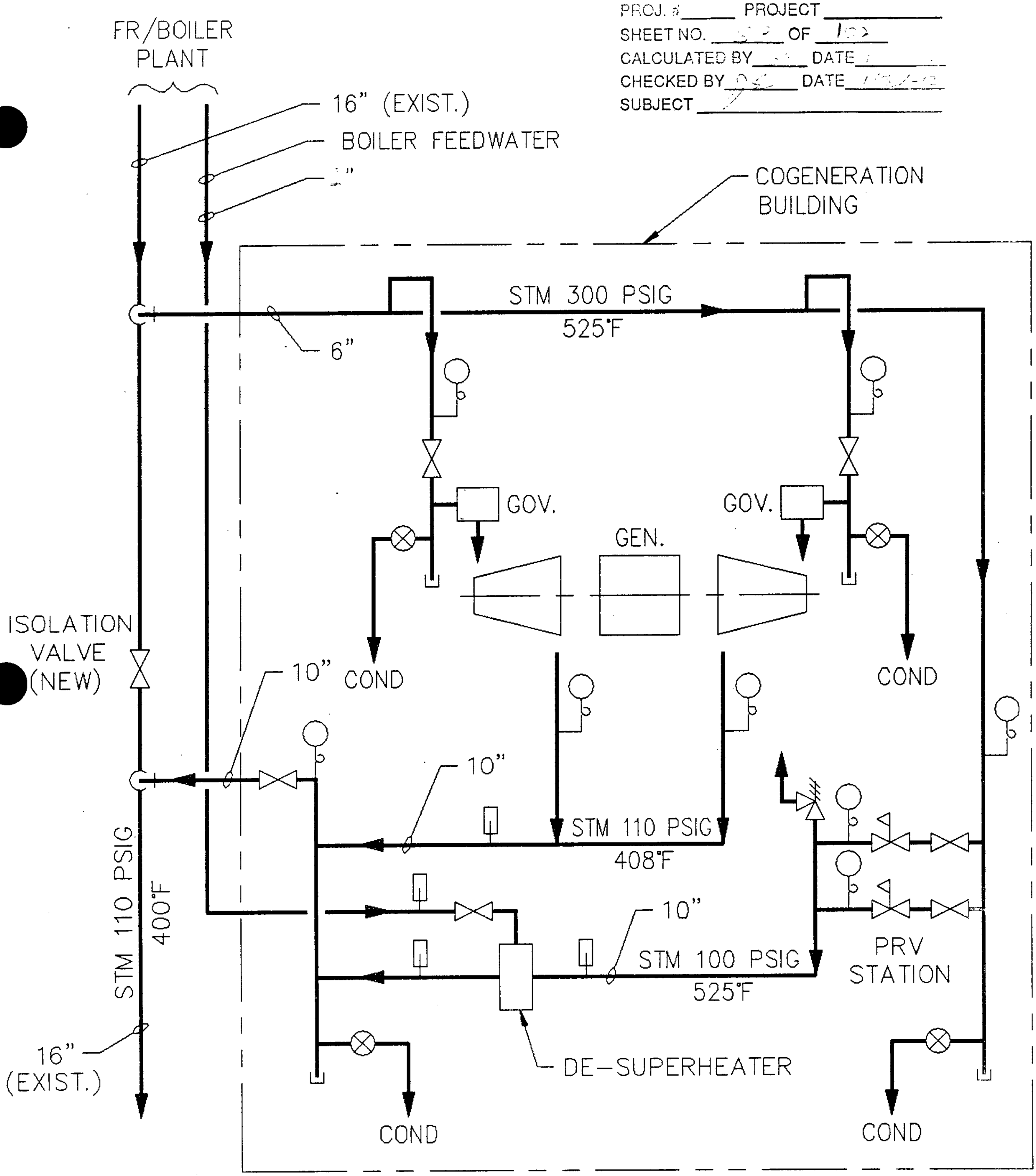


EMC ENGINEERS, INC.
PROJ. #______ PROJECT ______
SHEET NO. 62 OF 102
CALCULATED BY ______ DATE ______
CHECKED BY ______ DATE ______
SUBJECT ______

PROJ. #______ PROJECT ____________
SHEET NO. ______ OF ______
CALCULATED BY ______ DATE ______
CHECKED BY ______ DATE ______
SUBJECT ____________



STEAM PIPING SCHEMATIC

NO SCALE

BOILER FEEDWATER REQUIRED FOR DESUPERHEATER

Feedwater temperature	= 230°F (IN)	408°F (OUT)	Δt = 178°F
Feedwater pressure (assume)	= 325 psig		
Steam temperature	= 525°F (IN)	408°F (OUT)	Δt = 117°F
Steam flow rate	≅ 90,000 lb/hr		

A. Energy Released From:

Steam @ 110 psig, 525°F h ≅ 1289 Btu/lb

to

Steam @ 110 psig, 408°F h ≅ 1228 Btu/lb

61 Btu/lb

@ 90,000 lb/hr x 61 Btu/lb = 5,490,000 Btu/hr.

B. Energy Absorbed From:

Water @ 325 psig, 230°F h ≅ 207 Btu/lb

to

Steam @ 110 psig, 408°F h ≅ 1255 Btu/lb / -1048 Btu/lb

$$\therefore \frac{5{,}490{,}000\ Btu/hr}{1048\ Btu/lb} \cong 5240\ lb\ water/hr\ \text{converted to steam}.$$

$$\frac{5240\ lb/hr}{8.33\ lb/gal \times 60\ min/hr} \cong 10.5\ gpm\ \text{(feedwater flow rate)}.$$

Use 1" Schedule 80 steel pipe at 5.2 psi/100 LF head loss (@ 70°F).

EMC ENGINEERS, INC.
PROJ. #______ PROJECT ________
SHEET NO. ______ OF ______
CALCULATED BY______ DATE ______
CHECKED BY________ DATE ________
SUBJECT ______________

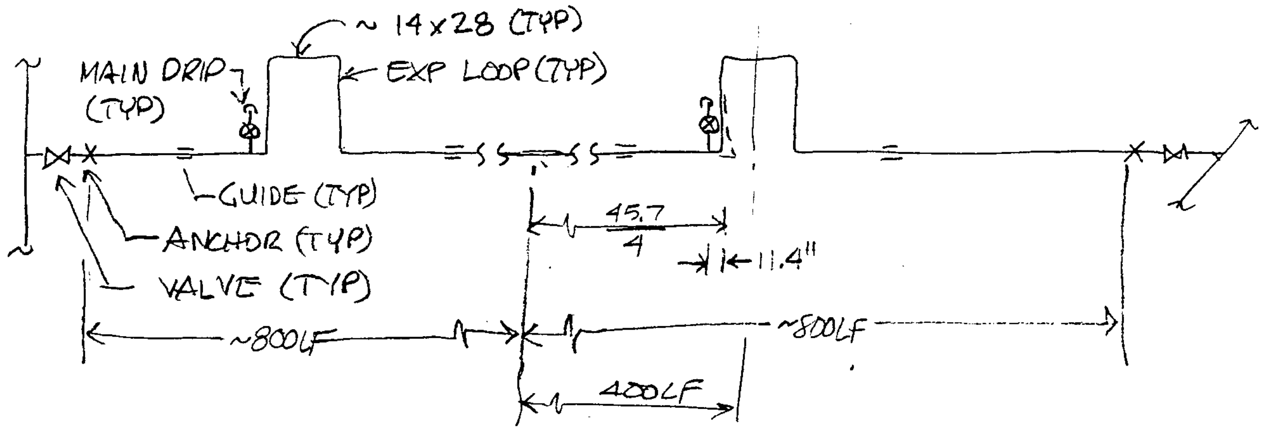
DESIGN STEAM LINE TO ADMINISTRATION AREA

1. Approximately 1600 LF or 6" pipe carrying steam at 300 psig (417°F).

2. Thermal expansion (T.E.) of carbon steel pipe at 417 °F: (70°F base).

$$T.E. = 2.86"/100\ LF \times 16 = 45.7"\ .$$

3.



Pipe:

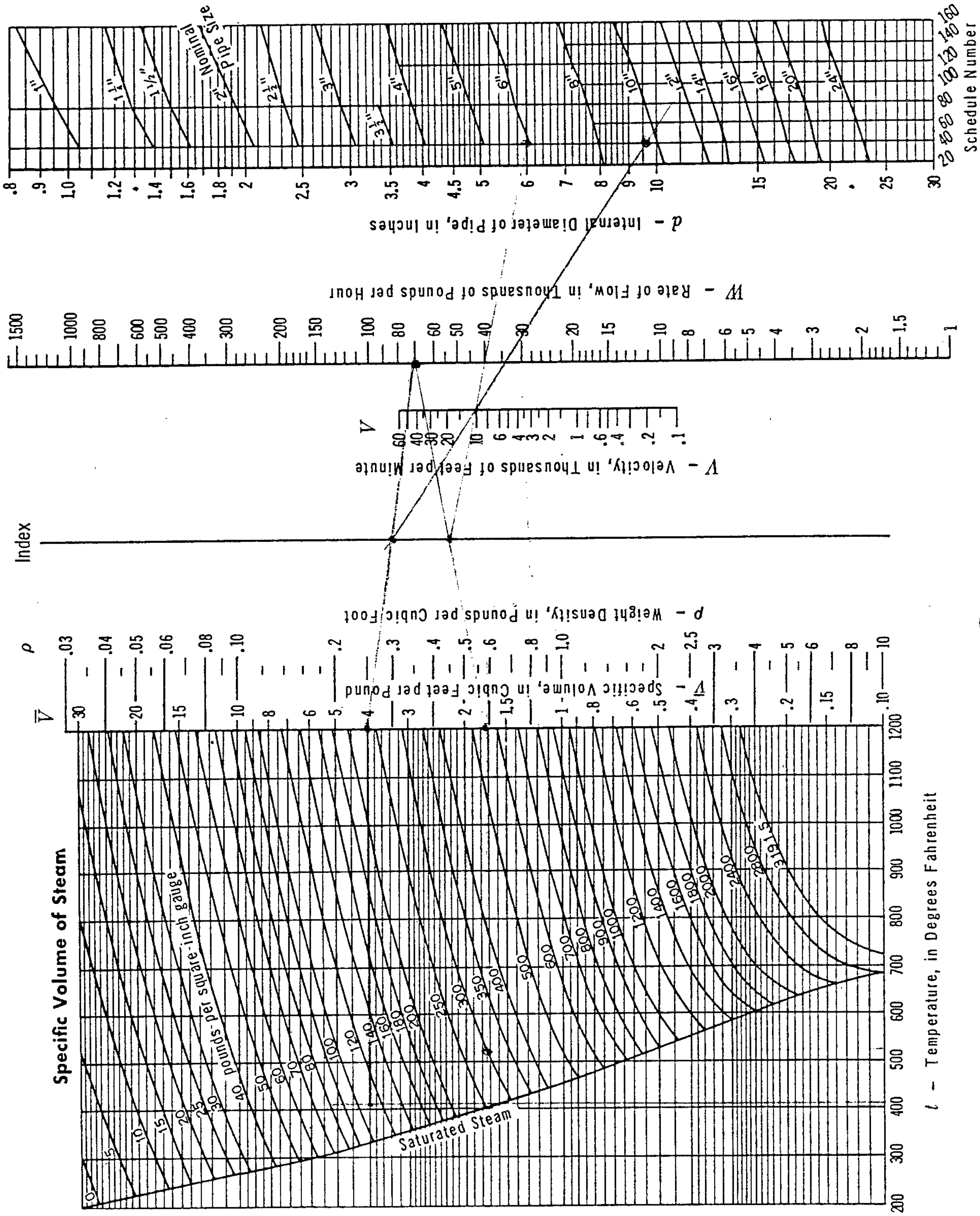
- Valves
- Anchors
- Glides
- Supports
- Traps
- Pipe-saddles
- Insulation & jacketing
- Piers

EMC ENGINEERS, INC.
PROJ. #_____ PROJECT _____
SHEET NO. _____ OF _____
CALCULATED BY_____ DATE_____
CHECKED BY_____ DATE_____
SUBJECT _____

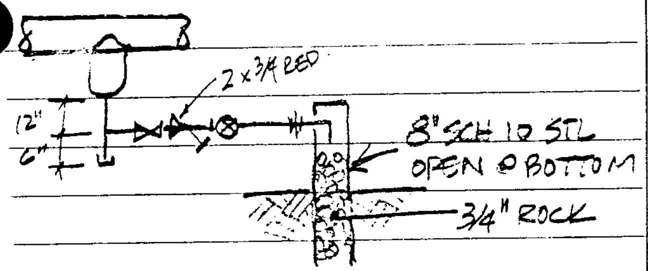
EMC ENGINEERS, INC.
PROJ. #______ PROJECT ______
SHEET NO. ______ OF ______
CALCULATED BY______ DATE______
CHECKED BY________ DATE______
SUBJECT ______________

Velocity of Compressible Fluids in Pipe

(continued)

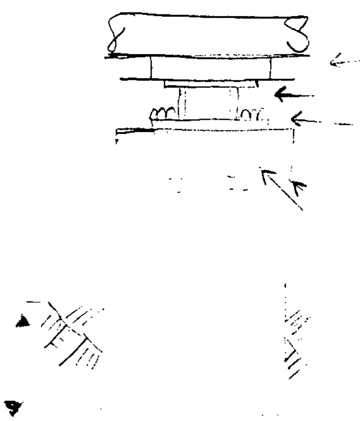


DRIP & TRAP ASSEMBLY



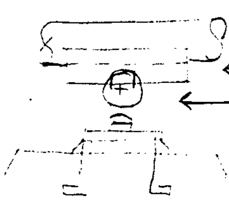
Description	Units	Mat'l. ($)	Labor (hrs)
2" Sch 80 stl pipe	2 LF	7	2.5
2" W/N flg. CL300	1 EA	15.44	0.889
2" tee	1 EA	21	1.455
3/4" El	2 EA	3	1.142
2" gate valve (flg) CL 300	2 EA	615	1.081
3/4" trap TD (CL600)	1 EA	490	0.8
8" Sch 10 Pipe	4 LF	80	8
3/4" Union	1 EA	6	0.615
3/4" Sch 80 Stl Pipe	5 LF	6	1.0
		1240	17.5

PIPE ANCHOR ASSEMBLY



	Mat'l.($)	Labor ($)
ST 3.5 x 10 x 12" long	10	6
8" Sch. 40 pipe	12	9
2-1/2" Steel plates w/3/4" dia. hole on 4 " sq in bottom plate	30	57
Concrete pier (Est. 2 cy avg. each)		
5/8" anchor bolts (4" sq. on center)	180	150
	232	222

PIPE SUPPORT ASSEMBLY 16' O.C. 112 Req'd.



	Mat'l. ($)	Labor ($)
2" pipe saddle	12	4
Chair & roller	20	5
1/2" steel plate with 5/8" bolts Top & anchor bolts bottom.	20	41
Pier 1-1/2 cy	53	30
	105	80

HOLSTON ARMY AMMUNITION PLANT
KINGSPORT, TENNESSEE
COGENERATION FEASIBILITY STUDY

Steam is presently generated at 315 psia in the central heating plant and distributed to the process buildings. At existing steam demand levels, the existing steam distribution system may be operated at a lower pressure; at 190 psia as is or at 125 psia with some modifications. EMC Engineers is performing a feasibility study to generate electricity with the pressure differential between 315 psia and the lower pressure. Preliminary analysis indicates an economic payback for a cogeneration system at about 2 years. We expect to be contracted to design the cogeneration system in 1992. We require quotes on cogeneration packages for both back pressures for the feasibility study. Packages should include the following:

Steam Turbine
- Inlet conditions - 315 psia, 525°F
- Flow rate - 80,000 LBH
- Exit Conditions - 190 psia and 125 psia (2 systems)
- Type - single or multistage (most economical)
- Electronic steam control system
- Dual electronic and mechanical overspeed trip mechanisms
- Speed reduction gears (if necessary)
- Package lubrication system including lube oil reservoir, filters, coolers, and pumps.
- Insulation and jacketing

Electric Generator
- High efficiency synchronous generator
- 13,800 volts at 60 Hz

Prewired Electrical Switchgear
- Circuit breaker (13.8 KV) including operator mechanism and undervoltage release.
- Utility grade protective relays
  - Over/under voltage
  - Over/under frequency
  - Reverse power
- Stator overtemperature trip
- Pilot lights for operating and trip status
- Ammeter, voltmeter, and kW/kWh meter
- Electronic digital tachometer
- Control power transformer
- Synchronous panels
  - Auto synchronization
  - Generator and bus metering
  - Voltage regulator and VAR controller

Package
- Baseplate
- Standard testing
- Installation drawing

We would also like a separate quote on available maintenance contracts.

FRY EQUIPMENT CO., INC.

2600 W. 2ND AVENUE SUITE 7 DENVER, COLORADO 80219 PHONE 303-922-8442

FAX: (303) 922-8445

EMC ENGINEERS, INC.
PROJ. # ______ PROJECT ______
SHEET NO. ______ OF 102
CALCULATED BY ______ DATE ______
CHECKED BY ______ DATE 1/13/92
SUBJECT ______

DATE: 9 JAN 92

TRANSMITTED TO: EMC

ATTENTION: [redacted] FROM: LOU GROUNDS

SUBJECT: Holston ARMY

This Transmission Consists of 4 Pages Including This Page.

(1) QUOTE FOR EWING "BP" TURBINE #227,580 → #280/k
813 KW @ 67,710 lbs/HR

(2) previous QUOTE FOR EWING "BP" TURBINE → #329/k
#173,500, 528 K.W. @ 54,000 lbs/HR

(3) previous QUOTE FOR MURRAY MULTI-STAGE → #312/kw
TURBINE, #500,000, 1600 KW @ 100,000 lbs/Hr

FRY EQUIPMENT COMPANY, INC.

2600 WEST 2ND AVENUE SUITE 7 DENVER, COLORADO 80219
PHONE 303-922-8442 FAX 303-922-8445

PROPOSA

No. 7363

Page 1 Of 1

REPLY TO: FRY EQUIPMENT COMPANY, INC.

TO: EMC Engineers
2750 S. Wadsworth Blvd.
Denver, CO 80236

JOB: Holston Army Munitions Department

LOCATION: Tennessee

Attn: Mr. Chet Butler P.E.

DATE: January 9, 1992

WE ARE PLEASED TO QUOTE ON EQUIPMENT AS FOLLOWS:

(1) Coppus Steam Turbine Generator, Ewing Model "BP", capacity of 813 KW when utilizing 67,710 lbs./hr. (maximum flow that the single stage turbine will pass - unable to pass 80,000 lbs./hr.). Based on 300 psig (525° F.), 110 psig exhaust, 3800 RPM turbine speed. System includes a Coppus RLHA-24 single stage turbine, Woodward 505 electronic governor, electronic pressure sensor, speed reduction gear, 480 volt synchronons generator, baseplate, two Rexnord spacer couplings, switchgear designed for parallel operation with the local utility - complete piping design engineering.

BUDGET PRICE: $227,580.00

Add Alternate "A" 13,800 volt generator from Kato Engineering, Add: $91,760.00 for generator and associated switchgear, and accessories.

SUBMITTED BY
FRY EQUIPMENT COMPANY, IN

MS Net 30 Days
DELIVERY 16-20 Weeks
WEIGHT 6500 lbs.

FOB South Deerfield, MA

Louis N. Grounds
Louis N. Grounds
Sales Engineer

FRY EQUIPMENT COMPANY, INC.

2600 WEST 2ND AVENUE SUITE 7 DENVER, COLORADO 80219
PHONE 303-922-8442 FAX 303-922-8445

PROPOSAL

No. 7348

Page 1 Of 1

REPLY TO: FRY EQUIPMENT CO., INC.

TO: EMC ENGINEERS
2750 S. Wadsworth Blvd.
Denver, CO 80236

JOB: Holston Army Munitions Depot

LOCATION: Tennessee

ATTN: Mr. Dennis Jones, P.E.

DATE: December 6, 1991

WE ARE PLEASED TO QUOTE ON EQUIPMENT AS FOLLOWS:

(1) Steam Turbine Generation, Coppus-Ewing Model "BP", capacity of 528 KW when utilizing 54,000 lbs/hr of steam flow at 525 deg. F thru a pressure drop of 300 psig to 125 psig.

Coppus RLHA-24 Single Stage Turbine, electronic steam controls, safety controls, 480 volt, 3600 RPM direct drive synchronous generator, standard pre-wired switchgear designed for parallel operation with the local utility. Steam piping engineering.

BUDGET PRICE: $173,500.00 Net F.O.B.

Add:

Start-up service, $500.00/day, engineer highly recommended but not mandatory.

FRY EQUIPMENT CO., INC.

SUBMITTED BY

Louis N. Grounds
Sales Engineer

Graduated payment schedule
or municipal lease

DELIVERY 14-18 weeks ARO

WEIGHT 4900 lbs.

FOB South Dearfield, MA

COPPUS® MURRAY TURBOMACHINERY CORPORATION

BURLINGTON, IOWA 52601 • TELEPHONE (319) 753-5431 • TELEX 757325

cc/ John Popek

Fou

FAX NUMBER 319-752-1616

TELEFAX MESSAGE

TO: Fry Equipment Denver, Colorado ATTN: Wayne Fry

TELEFAX NUMBER ________ DATE: Nov. 14, 1991

SUBJECT: EMC Engineers

SHEET 1 of 1 INCLUDING THIS SHEET

SIGNED John Graham

Murray Ref: G13034

I gave this "off the cuff" information to:

Mr. Dennis Jones
EMC Engineers
2750 South Wadsworth Blvd.
Denver, Colorado 80227
Phone 303-988-2951

Turbine Frame	1410	
Steam Conditions	300 PSIG - 525°F - 120 PSIG	130 / 30#
Steam Flow	100,000 LB/HR	- 120,000 #/HR
KW Produced	1600	
Turbine / Generator RPM	6000 / 1800	
Steam Rate	62.5 LB/KW/HR	
Inlet / Exhaust Size	8"/12"	
Gear S.F.	1.3	
Generator	4160 V / 3 Ph / 60 Hz / Synch / ODP	
Shipment	48 wks	
Estimated Price	$500,000	

1. Price includes turbine, gear, generator, baseplate, & switchgear
2. Final user is an Army Ammunition plant in Tennessee.
3. Please send MURRAY LITERATURE to Mr. Jones.

FRY EQUIPMENT COMPANY, INC.

2600 WEST 2ND AVENUE SUITE 7 DENVER, COLORADO 80219
PHONE 303-922-8442 FAX 303-922-8445

PROPOSAL

No. 7363

REPLY TO: FRY EQUIPMENT COMPANY, INC.

Page 1 Of 1

TO: EMC Engineers
2750 S. Wadsworth Blvd.
Denver, CO 80236

JOB: Holston Army Munitions Department

LOCATION: Tennessee

Attn: Mr. Chet Butler P.E.

DATE: January 9, 1992

WE ARE PLEASED TO QUOTE ON EQUIPMENT AS FOLLOWS:

Attn: GLENN BEARD P.E.

(1) Coppus Steam Turbine Generator, Ewing Model "BP", capacity of 813 KW when utilizing 67,710 lbs./hr. (maximum flow that the single stage turbine will pass - unable to pass 80,000 lbs./hr.). Based on 300 psig (525° F.), 110 psig exhaust, 3800 RPM turbine speed. System includes a Coppus RLHA-24 single stage turbine, Woodward 505 electronic governor, electronic pressure sensor, speed reduction gear, 480 volt synchronons generator, baseplate, two Rexnord spacer couplings, switchgear designed for parallel operation with the local utility - complete piping design engineering.

BUDGET PRICE: $227,580.00

Add Alternate "A" 13,800 volt generator from Kato Engineering, Add: $91,760.00 for generator and associated switchgear, and accessories.

Add Alternate "B" 4160 volt generator complete with associated switchgear, (step up transformer - by others) add: $24,370.00 to base price. New total price: $251,950.00

SUBMITTED BY
FRY EQUIPMENT COMPANY, INC.

TERMS Net 30 Days
DELIVERY 16-20 Weeks
WEIGHT 6500 lbs.

FOB South Deerfield, MA

Louis N. Grounds

DRESSER-RAND

Steam Turbine, Motor & Generator Division
1240 N. Lakeview, Suite 200
Anaheim, CA 92807

Phone: 714/693-0706
Fax: 714/693-9031

EMC ENGINEERS, INC.
PROJ. #______ PROJECT ________
SHEET NO. ___ OF ___
CALCULATED BY ___ DATE ___
CHECKED BY ___ DATE ___
SUBJECT ________

DATE: 1/9/92

FAX TRANSMITTAL

TO: Mr. Dennis Jones

FROM: CHRISTOPHER P. BOVE

cc: EMC Eng 303-985-2527

cc: ________

THERE WILL BE _____ PAGE(s) FOLLOWING THIS COVER PAGE.

==

SUBJECT: OUR 2/WE28/002
HAAP Cogen.

Dennis:

Please see attached quotation. A hard copy is being sent in the mail. If you have any questions, please don't hesitate to call.

Chris

DRESSER-RAND
Electric Machinery
Terry
Turbodyne

Steam Turbine, Motor & Generator Division
1240 N. Lakeview, Suite 200 Anaheim, CA 92807
714/693-0706 FAX: 714/693-9031

January 9, 1992

EMC Engineers, Inc.
2750 S. Wadsworth Blvd., C-200
Denver, Colorado 80227-3493

Attention: Mr. Dennis Jones

Subject: HAAP Cogeneration Feasibility Study
Kingsport Tennesee
Steam Turbine Generator Set
Dresser-Rand #2/WE28/002

Gentlemen:

Thank you for your inquiry regarding Dresser-Rand Steam Turbines.

We are very happy to respond with the following proposal. Please find attached to this letter details of the equipment we are offering along with form ST-302, our Standard Conditons of Sale.

If you have any further questions, or require additional information, please feel free to contact our office at your earliest convenience. We are most anxious to be of help to you not only on this project but at any time.

Sincerely,

Christopher P. Bove/ms

Christopher P. Bove
Sales Representative

ms

cc: B. Oakleaf, D-R Wellsville
B. Plant, D-R Bethesda
D. Stowell, George S. Edwards Co., Inc., Marietta, GA

Attachments: Forms ST-302, ST-124, 8802-SST, 8803-MST,
8903-G, 8901-STG

EMC Engineers Inc.
2/WE28/002
January 9, 1992

Item Number	OPTION I - Multistage
Dresser-Rand Model	"TS" MST

CONDITIONS OF SERVICE

Power (EKW)	1150
Speed (RPM)	5000/1800
Steam Flow (#/HR)	80,000
Inlet Pressure (PSIG)	300
Inlet Temperature (°F)	525
Exhaust Pressure (PSIG)	110

TECHNICAL

Inlet, Size/Location	8" 400 LB RF
Exhaust, Size/Location	12" 150 LB FF
Weight (LB)	26,000 est.

COMMERCIAL

Price (each) *	$455,000
Shipment (weeks) **	44-46

* F.O.B., Wellsville, New York.

** (Subject to Prior Sale) Promise dates are from receipt of order with sufficient information and authorization to proceed. Shipping lead times are approximate and are subject to factory verification at time of order.

*** Maximum casing exhaust pressure is 160 psig.

EMC Engineers Inc.
2/WE28/002
January 9, 1992

OPTION I - Multistage

INCLUDED FEATURES AND ACCESSORIES:

- Woodward NEMA Class "D" Electronic 505 Governor with Valtek pneumatic actuator
- (1) Handvalves
- Manual Speed Changer
- Mechanical Emergency Trip and Throttle Valve
- Built-Up Rotor Construction and forged wheels
- Self-Equalizing Tilting Pad Thrust Bearing
- Labyrinth Shaft Seals
- Gland Condenser
- Sentinel Warning Valve
- Pressure Lube system for turbine and gear
- Shaft Driven Main Oil Pump
- Motor Driven Auxiliary Pump
- Single Oil Cooler
- Dual Oil Filter 25 Micron
- Oil Reservoir in Baseplate
- Six (6) Instruction Manuals
- One-half Hour No-Load Run Test
- Baseplate, under turbine, gear & generator
- Insulation & Jacketing
- Gaugeboard, local on baseplate
- Solenoid Trip
- High speed & low speed couplings
- Certified Hydro Test
- Certified No-Load Test
- Kato or equal generator, 13.8 KV
- Dresser-Rand or equal reduction gear
- Torsional Analysis
- Combined outline drawing
- Performance Curve
- Casing design - 700# psig - 750°F - 160 psig
- Mechanical & electronic overspeed trip

ADDITIONAL FEATURES AND ACCESSORIES:	PRICE EACH
- Additional Instruction Manuals	$ 60

EMC Engineers Inc.
2/WE28/002
January 9, 1992

Item Number	OPTION II - Single Stage	
Dresser-Rand Model	503HE - E	Part Load

CONDITIONS OF SERVICE

Power (EKW)	750	400
Speed (RPM)	4500/1800	
Steam Flow (#/HR)	65,000	65,000
Inlet Pressure (PSIG)	300	300
Inlet Temperature (°F)	525	525
Exhaust Pressure (PSIG)	110	175

TECHNICAL

Inlet, Size/Location	6" 600 LB RF
Exhaust, Size/Location	8" 150 LB FF
Weight (LB)	14,000 est.

COMMERCIAL

Price (each) *	$136,000
Shipment (weeks) **	28-30

* F.O.B., Wellsville, New York.

** (Subject to Prior Sale) Promise dates are from receipt of order with sufficient information and authorization to proceed. Shipping lead times are approximate and are subject to factory verification at time of order.

EMC Engineers Inc.
2/WE28/002
January 9, 1992

Item Number	OPTION III - Single Stage
Dresser-Rand Model	503H

CONDITIONS OF SERVICE

Power (EKW)	420
Speed (RPM)	3600
Steam Flow (#/HR)	65,000
Inlet Pressure (PSIG)	300
Inlet Temperature (°F)	525
Exhaust Pressure (PSIG)	175

TECHNICAL

Inlet, Size/Location	6" 600 LB RF
Exhaust, Size/Location	8" 150 LB FF
Weight (LB)	11,000 est.

COMMERCIAL

Price (each) *	$119,000
Shipment (weeks) **	28

* F.O.B., Wellsville, New York.

** (Subject to Prior Sale) Promise dates are from receipt of order with sufficient information and authorization to proceed. Shipping lead times are approximate and are subject to factory verification at time of order.

OPTION II - Single Stage
and
OPTION III - Single Stage

INCLUDED FEATURES AND ACCESSORIES:

- Woodward NEMA Class "D" Electronic 505 Governor with Valtek pneumatic actuator
- (2) Handvalves(s)
- Manual Speed Changer
- Mechanical Emergency Trip Valve
- Steam Strainer, Integral & Removable
- Built-Up Rotor Construction with Forged Wheels
- Ball Thrust Bearing
- Carbon Shaft Seals
- Sentinel Warning Valve
- Ring Oil Type Lubrication with Trico Oilers
- Pressure Lube on gear only
    - Shaft Driven Main Oil Pump
    - Single Oil Cooler
    - Single Oil Filter 25 Micron
- Six (6) Instruction Manuals
- One-half Hour No-Load Run Test
- Baseplate, under turbine, gear & generator
- Insulation & Jacketing, painted steel
- Gaugeboard, local
- Solenoid Trip
- High speed and low speed couplings
- Certified Hydro Test
- Certified No-Load Test
- Kato or equal generator - 460 KV
- Dresser-Rand or equal reduction gear - Option II only
- Torsional Analysis
- Combined Outline Drawing
- Performance Curve
- Casing Design Maximum - 700 psig - 750°F - 300 psig
- Mechanical and electronic overspeed trip

ADDITIONAL FEATURES AND ACCESSORIES:	PRICE EACH
- Additional Instruction Manuals	$ 60

EMC ENGINEERS, INC.
PROJ. #______ PROJECT ______
SHEET NO. 81 OF ______
CALCULATED BY ______ DATE ______
CHECKED BY ______ DATE ______
SUBJECT ______

EMC Engineers Inc.
2/WE28/002
January 9, 1992

OPTIONS:

A)	13.8 KV Generator	Option I	-	Included
		Option II	-	Add $58,000 net
		Option III	-	Add $50,000 net

B) Switchgear including:

- Circuit breaker with operator mechanism and under voltage release
- Protective Relays
  - over/under voltage
  - over/under frequency
  - reverse power
- Stator overtemperature trip
- Pilot lights for operating and trip status
- Ammeter, voltmeter, KW/MW meter
- Control power transformer
- Governor mounted in switchgear
- Synchronous panels
-
  - auto synchronization
  - generator and bus metering
  - voltage regulator and VAR controller

Option I - 13.8 KV ADD $87,000 net

Option II & III - 480 KV ADD $67,000 net (NOTE: Use Option I adder for 13.8 KV)

DRESSER-RAND

STEAM TURBINE, MOTOR & GENERATOR DIVISION

STANDARD CONDITIONS OF SALE

"These are the terms of payment applicable to products from the Steam Turbine, Motor & Generator Division of the Dresser-Rand Plant in Wellsville, New York. When these terms and conditions are included in, or attached to, a proposal made by Dresser-Rand, said proposal shall remain open for thirty (30) days and in the meantime may be changed or withdrawn. These terms and conditions shall exclusively govern the sale and Purchaser's acceptance of Dresser-Rand's proposal and is expressly limited to these terms and conditions. Dresser-Rand hereby gives notice that it objects to any additional or different terms and conditions which may be contained in Purchaser's assent to Dresser-Rand's terms and conditions."

TERMS OF PAYMENT

A. These are the Steam Turbine, Motor & Generator Division's of Dresser-Rand standard terms of payment for **domestic** orders.

On all orders **under $100,000** regardless of manufacturing schedule; and those orders **over $100,000** with a manufacturing schedule of less than six (6) months.

Net cash within thirty (30) days after shipment, or after notification that Dresser-Rand is ready to ship. These terms apply to partial as well as complete shipments.

On orders **over $100,000** with a manufacturing schedule of six (6) months or longer:

10% — With Purchaser's Order, Letter of Intent, or written authorization, whichever bears the earliest date.

80% — In approximately equal payments every sixty (60) days, to commence sixty (60) days after date of Purchaser's order and to continue through the balance of the proposed manufacturing schedule.

10% — Due upon shipment or notification that Dresser-Rand is ready to ship.

B. "Dresser-Rand's standard terms of payment for **export** orders are the same as stated above for domestic orders except that the Purchaser shall promptly, after placement of order, establish an irrevocable letter of credit covering the full purchase price less any payment made upon placement of order confirmed by a bank in New York, NY which will authorize payment to the Steam Turbine, Motor & Generator Division of Dresser-Rand against its presentation of commercial invoices, packing lists and shipping documents. If other terms are acceptable, they must be set forth elsewhere in the proposal or order or must be set forth in some other writing signed by Dresser-Rand."

PRICE ADJUSTMENT

The following clauses are applicable to the extent they are referred to elsewhere in this proposal. Any purchased material whose price will be adjusted to reflect the vendor's price in effect at the time of shipment is listed as an exception.

Clause A — **The prices named herein for Dresser-Rand equipment are not subject to any change from the prices in effect on the date the order is accepted.**

Clause B — **The prices named herein for Dresser-Rand equipment will be adjusted to the price in effect at the time of shipment.**

Clause C — **The prices named herein for Dresser-Rand equipment are firm for all deliveries within the first twelve (12) months after the date of the purchase order. For quoted deliveries "longer than twelve (12) months", or for deliveries "extended beyond twelve (12) months" for the customer's convenience, the prices named herein will be adjusted from the twelfth month after the date of contract to the month of shipment in accordance with the following adjustment clause.**

Clause D — **The prices named herein for Dresser-Rand equipment will be adjusted from the date of the contract to the month of shipment in accordance with the following adjustment clause.**

ADJUSTMENT CLAUSE

The prices will be adjusted upward or downward for the time stated above for changes in labor and material costs, based on 45% of the contract price representing the amount of labor and 55% of the contract price representing the amount of material. The labor portion shall be adjusted in accordance with the union contract in effect at the Steam Turbine, Motor & Generator Division of Dresser-Rand plant in Wellsville, New York. The material portion shall be adjusted in accordance with the Foundry and Forge Shop Products Index (Code 1015) as determined and reported monthly by the Bureau of Labor Statistics, U.S. Department of Labor's Wholesale Prices and Price Indexes Publications. In no case shall the final price be less than the contract price.

DRESSER-RAND COMPANY
GENERAL TERMS OF SALE — EQUIPMENT AND PARTS

1. General
Seller's prices are based on these sales terms. This document together with any additional writings signed by Seller shall represent the final, complete and exclusive agreement between the parties for the sale and use of Seller's equipment, spare and replacement parts, service work incidental thereto and all related matters, and may not be modified, supplemented, explained or waived by parol evidence or in any other way, except in a writing signed by an authorized representative of Seller. Unless prior written agreement is reached, any work commenced by Seller shall be in accordance with the terms and conditions set forth herein. Any reference by Seller to Buyer's specifications and similar requirements are only to describe the products and work covered hereby and no warranties or other items therein shall have any force or effect. Catalogs, circulars and similar pamphlets of the Seller are issued for general information purposes only and shall not be deemed to modify the provisions hereof.

2. Taxes
Any sales, use, or other taxes and duties imposed on this sale, or on this transaction, are not included in the price. Such taxes shall be billed separately to the Buyer. Seller will accept a valid exemption certificate from the Buyer if applicable; however, if an exemption certificate previously accepted is not recognized by the governmental taxing authority involved and the Seller is required to pay the tax covered by such exemption certificate, Buyer agrees to promptly reimburse Seller for the taxes paid.

3. Title and Risk of Loss
Full risk of loss (including transportation delays and losses) and title shall pass to Buyer upon delivery of products to the F.O.B. point or if Seller consents to a delay in shipment beyond the scheduled date at the request of Buyer, upon notification by Seller to Buyer that the products are ready for shipment. However, Seller retains title, for security purposes only, to all products until paid for in full in cash and Seller may, at Seller's option, repossess the same, upon Buyer's default in payment hereunder, and charge Buyer with any deficiency.

4. Delivery and Delays
A. The Seller shall use its best efforts to meet its promised delivery dates. It is understood that Seller's delivery dates are good faith estimates made by Seller at the time of quotation or date of order, as applicable.

B. The Seller shall not be liable for any non-performance or delay due to war, riots, fire, flood, strikes or other labor difficulty, governmental actions, acts of the Buyer, delays in transportation, inability to obtain necessary labor or materials from usual sources, or other causes beyond the reasonable control of the Seller. In the event of delay in performance due to any such cause, the date of delivery or time for completion will be adjusted to reflect the length of time lost by reason of such delay. The Buyer's receipt of the equipment, spare or replacement parts shall constitute a waiver of any claims for delay.

5. Patents
Seller agrees to assume the defense of any suit for infringement of any United States patents brought against Buyer to the extent such suit charges infringement of an apparatus or product claim by Seller's product in and of itself, provided (i) said product is built entirely to Seller's design, (ii) Buyer notifies Seller in writing of the filing of such suit and Seller has the right to defend, settle and make changes in the product for the purpose of avoiding infringement. Seller assumes no responsibility for charges of infringement of any process or method claims, unless infringement of such claim is the result of following specific instructions furnished by Seller.

6. Manufacturing Sources and Standards
A. To maintain delivery schedules and to best utilize Seller's manufacturing capacity, Seller reserves the right to have all or any part of the Buyer's order manufactured at any of Seller's, its subsidiaries or licensee's plants on a worldwide basis.

B. Seller reserves the right to change its specifications, drawings, and standards with the provision that such changes will not impair the performance of its products or parts, and further that such products, and parts will meet any of Buyer's specifications and other specific product requirements previously agreed to and made a part of this agreement.

7. Acceptance and Inspection
A. All products shall be finally inspected and accepted by Buyer within fourteen (14) days after delivery. Buyer shall make all claims (including claims for shortages) excepting only those provided for under the WARRANTY and PATENTS clauses herein in writing within said fourteen (14) day period or they are waived. There shall be no revocation of acceptance. Rejection may be only for defects substantially impairing the value of products or work and Buyer's remedy for lesser defects shall be in accordance with the WARRANTY clause herein.

B. If Buyer wrongfully rejects or revokes acceptance of items tendered under this agreement, or fails to make a payment due on or before delivery, or repudiates this agreement, Seller shall, at its option, have a right to recover as damages either the price as stated herein (upon recovery of the price the items involved shall become the property of the Buyer) or the profit (including reasonable overhead) which the Seller would have made from full performance, together with reasonable costs and expenses incurred.

8. Warranty
A. The Seller warrants that the equipment manufactured by it and delivered hereunder will be free from defects in material and workmanship for a period of twelve (12) months from the date of initial startup or eighteen (18) months from the date of shipment, whichever shall first occur. In the case of spare or replacement parts manufactured by Seller, the warranty period shall be for a period of six (6) months from initial use of the part or nine (9) months from shipment of such part, whichever shall first occur. The Buyer shall be obligated to promptly report any claimed defect in writing to the Seller immediately upon discovery and, in any event, within the above period. After notice from Buyer and substantiation of the claim, Seller shall, at its option, correct such defect either by suitable repair to such equipment or part, or by furnishing replacement equipment or part(s), as necessary, to the original F.O.B. point of shipment.

B. THE SELLER MAKES NO OTHER WARRANTY OR REPRESENTATION OF ANY KIND. ALL OTHER WARRANTIES, EXPRESSED OR IMPLIED, INCLUDING BUT NOT LIMITED TO, THE IMPLIED WARRANTIES OF MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE ARE HEREBY DISCLAIMED.

C. With respect to equipment, parts and work not manufactured or performed by Seller, Seller's only obligation shall be to assign to Buyer whatever warranty Seller receives from the manufacturer.

D. The Seller shall not be liable for the cost of any repair, replacement, or adjustment to the equipment or parts made by the Buyer or for labor performed by the Buyer or others, without the Seller's prior written approval.

E. No equipment or part furnished by Seller shall be deemed to be defective by reason of normal wear and tear, failure to resist erosive or corrosive action of any fluid or gas, or Buyer's failure to properly store, install, operate or maintain the equipment in accordance with good industry practices or specific recommendations of Seller.

F. The Buyer shall not operate equipment which is considered to be defective without first notifying the Seller in writing of its intention to do so. Any such use of the equipment will be at the Buyer's sole risk and expense.

G. The repair or replacement of the equipment, spare or replacement part(s) by the Seller under this Warranty provision, shall constitute Seller's sole obligation and Buyer's sole and exclusive remedy for all claims of defects regarding the equipment and parts furnished hereunder.

9. Limitation of Liability
A. The remedies of the Buyer set forth herein are exclusive and the total liability of the Seller with respect to claims under this contract or regarding the equipment, spare or replacement parts and services incidental thereto as furnished hereunder, whether based in contract, tort (including negligence and strict liability) or otherwise, shall not exceed the purchase price of the unit of equipment or part(s) upon which such liability is based.

B. The Seller shall in no event be liable for any consequential, incidental, indirect, special or punitive damages arising out of this contract or any breach thereof, or any defect in, or failure of, or malfunction of the equipment or part(s) hereunder, including but not limited to, claims based upon loss of use, lost profits or revenue, interest, lost goodwill, work stoppage, impairment of other goods, loss by reason of shutdown or non-operation, increased expenses of operation, cost of purchase of replacement power or claims of Buyer or customers of Buyer for service interruption whether or not such loss or damage is based on contract, tort (including negligence and strict liability) or otherwise.

C. Any action by Buyer arising hereunder or relating hereto, whether based on breach of contract, tort (including negligence and strict liability) or other theories, must be commenced within one (1) year after the cause of action accrues or it shall be barred.

10. Nuclear Liability
In the event that the equipment or parts sold hereunder are to be used in a nuclear facility, the Buyer shall, prior to such use, arrange for insurance or a governmental indemnity protecting the Seller against liability and hereby releases and agrees to indemnify the Seller and its suppliers from any nuclear damage, including loss of use, which in any manner arises out of a nuclear incident, whether alleged to be due, in whole or in part, to the negligence or other cause of the Seller or its suppliers.

11. Assignment
Except as to Seller's rights under Article 6 (A), herein, neither party shall assign or transfer this contract without the prior written consent of the other party, which shall not be unreasonably withheld.

12. Governing Law
The rights and obligations of the parties shall be governed by the laws of the State of New York.

DRESSER-RAND

STANDARD CONDITIONS
OF SALE

Service Representative (Domestic)

a. The machinery shall be installed and put in operation by and at the expense of the Purchaser. Upon request of the Purchaser, Dresser-Rand will furnish the services of a Service Representative to advise and assist the Purchaser in the installation of the machinery. Purchaser shall furnish safe and proper working conditions, and safe storage of any special tools. The Purchaser shall furnish all necessary help, labor, cranes, cribbing, oil, supplies, station operating force, steam, electricity, water and other material and supplies required to install and operate the machinery and shall furnish free available crane and switching service and the services of operators and other employees that may be necessary in connection therewith.

b. Dresser-Rand shall not be responsible for materials furnished by the Purchaser or for acts or failures to act of personnel furnished by the Purchaser, nor shall Dresser-Rand be responsible for the construction of foundations or for the nature of the soil upon which they are built.

c. Unless otherwise stipulated, these services are available to the Purchaser at the following terms:

(1) At the rate of $ 625.00 for each standard eight hour day worked or spent in travel to and from the job site, including any local living expenses. All travel expenses from the time of leaving base location until return thereto and all shipping charges for any special tools and materials will be additional charges at actual cost.

(2) Hours worked in excess of the normal eight hour day, Monday through Friday, and hours worked on Saturday, Sunday and Holidays, will be billed at the rate of [illegible] per hour.

(3) The rates specified above are not subject to change provided the Service Representative begins to perform these services within 90 days after the equipment is shipped.

(4) The minimum billing for less than four hours worked or spent in travel will be 50% of the daily rate. The minimum billing for more than four hours but less than eight hours worked or spent in travel will be the full daily rate.

(5) The time when the Service Representative is ready, willing and able to work at the job site, Monday through Friday, shall be considered to be time worked for the purposes of this paragraph, even though his services are not in fact utilized.

(6) The rate quoted in **c.** (1) does not include living expenses for Saturday, Sunday and Holidays when the Service Representative is available for work at the job site. Subsistence for these days will be billed at $ [illegible] per day.

d. Dresser-Rand shall not in any event be held liable for any special, indirect or consequential damages.

DRESSER-RAND

Steam Turbine, Motor & Generator Division
Wellsville, NY 14895

SINGLE STAGE MATERIALS OF CONSTRUCTION

TURBODYNE CLASS	1	2	3	4	5	6
NEMA CLASS	1	5	6	9	10	11
Steam Inlet Portion of Case	ASTM A278 Cast Iron CL. 40	ASTM A216 Cast Steel GR. WCB	ASTM A216 Cast Steel GR. WCB	ASTM A216 Cast Steel GR. WCB	ASTM A217 Carbon Moly GR. WCI	ASTM A217 Chrome Moly GR. WC6
Top Portion of Case and Exhaust Portion	ASTM A278 Cast Iron CL. 40	ASTM A278 Cast Iron CL. 40	ASTM A216 Cast Steel GR. WCB	ASTM A216 Cast Steel GR. WCB	ASTM A216 Cast Steel GR. WCB (1)	ASTM A216 Cast Steel GR. WCB (2)
Steam Chest	ASTM A278 CL 40 CI / CI	ASTM A216 GRWCB Cast Stl	ASTM A216 GRWCB Cast Stl	ASTM A216 GRWCB Steel	ASTM A217 GRWC6 Carbon Moly	ASTM A217 GRWC1 Chrome Moly
Nozzle Ring	ASTM A285 Stl Plate*	ASTM A285 Stl Plate*	ASTM A285 Stl Plate*	ASTM A285 Stl Plate	ASTM A285 Stl Plate*	ASTM A285 Stl Plate
Buckets & Shroud Bands	AISI 403 Stainless Steel	AISI 403 Stainless Steel	AISI 403 Stainless Steel	AISI 403 Stainless Steel	AISI 403 Stainless Steel	AISI 403 Stainless Steel
Emergency Gov Valve	ASTM A582 Stainless Steel	ASTM A582 Stainless Steel	ASTM A582 Stainless Steel	ASTM A582 Stainless Steel	ASTM A582 Stainless Steel	ASTM A582 Stainless Steel
Packing Rings	Carbon	Carbon	Carbon	Carbon	Carbon	Carbon
Packing Ring Spacers	ASTM A240 Stainless Steel	ASTM A240 Stainless Steel	ASTM A240 Stainless Steel	ASTM A240 Stainless Steel	ASTM A240 Stainless Steel	ASTM A240 Stainless Steel
Packing Ring Springs	Inconel	Inconel	Inconel	Inconel	Inconel	Inconel
Brg. Journal	Stl & Babbitt	Stl & Babbitt	Stl & Babbitt	Stl & Babbitt	Stl & Babbitt	Stl & Babbitt

Material supplied is minimum grade. Forgings will be supplied where conditions dictate unless ordered as optional.

*Stainless Optional

DRESSER-RAND

Steam Turbine, Motor & Generator Division
Wellsville, NY 14895

MULTISTAGE MATERIALS OF CONSTRUCTION

PART	CLASS I	CLASS II OR III
Steam End	Cast Iron ASTM A 278 Cl 40	Cast Steel ASTM A 216 Gr WCB
Barrel and Exhaust End	Cast Iron ASTM A 278 Cl 40 Cast Steel ASTM A 216 GWCB	MTL. Depends on Size and Temp.
Nozzle Ring	Steel Plate ASTM A 285 Gr C	Steel Plate ASTM A 285 Gr C
Diaphragm Nozzles	Stainless Steel AISI 403	Stainless Steel AISI 403
Shaft SAE 4140	Hot Rolled Steel Alloy*	Hot Rolled Steel Alloy*
Wheels SAE 1045	Open Hearth Carb Steel Plate*	Open Hearth Carb Steel Plate*
Buckets & Shroud Bands	Stainless Steel AISI 403	Stainless Steel AISI 403
Governor Valve, Seats & Stem	Stainless Steel ASTM A 351 Gr 420	Stainless Steel ASIM A 351 Gr 420
Emergency Governor Valve	Stainless Steel ASTM A 582 Gr 416	Stainless Steel ASTM A 582 Gr 416
Packing Rings	Carbon	Carbon
Packing Ring Spacers	Stainless Steel ASTM A 240 Gr D	Stainless Steel ASTM A 240 Gr D
Packing Ring Springs	Inconel	Inconel
Steam Strainer	Stainless Steel AISI 302	Stainless Steel AISI 302
Journal Bearings	Babbitt Lined	Babbitt Lined

*Material specified is minimum grade. Forgings will be supplied as dictated by speed, pressure and temperature.

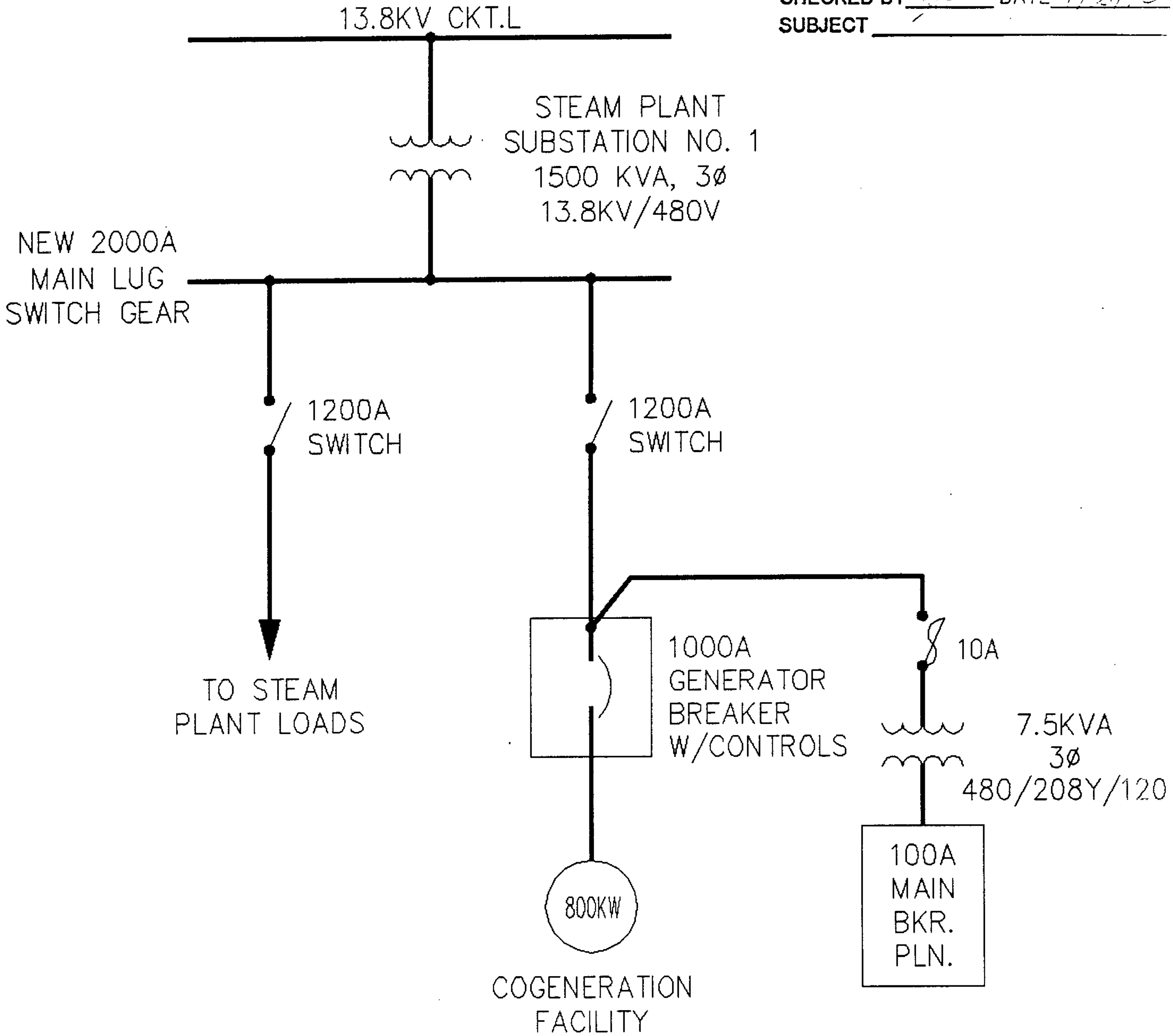
COGENERATION QUOTES

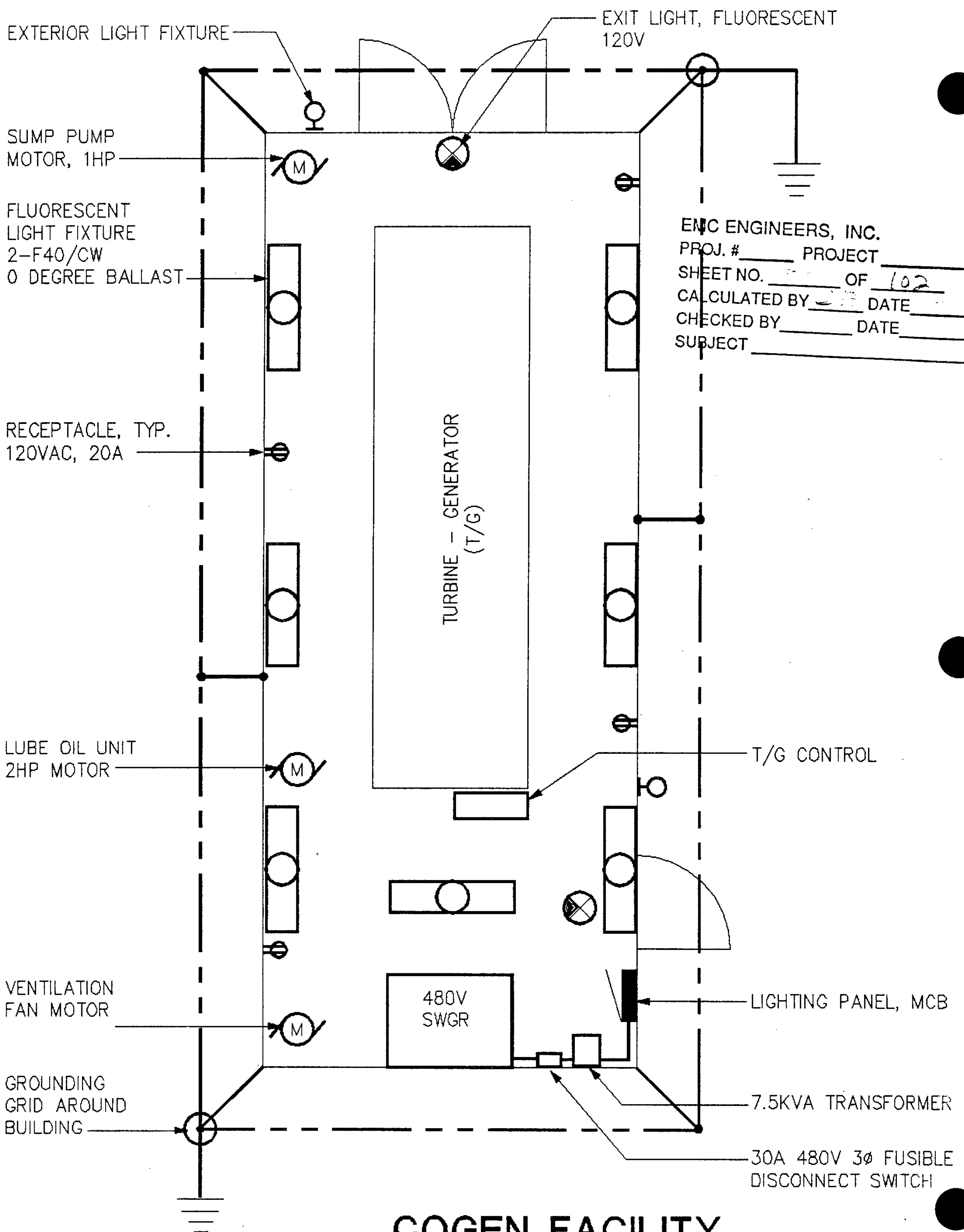
MANUFACTURE	OPTION	POWER OUTPUT (KW)	STEAM FLOW (LBH)	VOLTAGE (KV)	STEAM PIPING PRESS (PSIG)	BASE COST ($)	SWITCH GEAR COST ($)	ADDED GNRTR COST ($)	TOTAL T/G SET COST ($)	SUPPORT SYSTEM COST ($)	ADDED ELECTRIC COST ($)	ADDED DSTRB COST ($)	TOTAL COST ($)	STEAM RATE (LBH/KW)	ANNUAL COST SAVINGS ($)	SIMPLE PAYBACK (YRS)
COPPUS-EWING	1	813	67,700	460	110	$227,580	NONE	NONE	$365,124	$146,802	$97,629	$133,894	$743,449	83	$187,937	4.0
DRESSER-RAND	2	750	65,000	460	110	$136,000	$67,000	NONE	$327,487	$146,802	$97,629	$133,894	$705,812	87	$173,610	4.1
DRESSER-RAND	1	1,150	80,000	13,800	110	$455,000	$87,000	NONE	$846,564	$146,802	$97,629	$133,894	$1,224,889	70	$240,511	5.1
COPPUS-EWING	2	813	67,700	13,800	110	$227,580	$33,760	$58,000	$505,627	$146,802	$97,629	$133,894	$883,952	83	$187,937	4.7
DRESSER-RAND	2	750	65,000	13,800	110	$136,000	$87,000	$58,000	$446,921	$146,802	$97,629	$133,894	$825,246	87	$173,610	4.8
DRESSER-RAND	3	420	65,000	460	175	$119,000	$67,000	NONE	$301,457	$146,802	$97,629	NONE	$545,888	155	$107,336	5.1
DRESSER-RAND	2	400	65,000	460	175	$136,000	$67,000	NONE	$327,487	$146,802	$97,629	NONE	$571,918	163	$102,132	5.6
DRESSER-RAND	3	420	65,000	13,800	175	$119,000	$87,000	$50,000	$408,641	$146,802	$97,629	NONE	$653,072	155	$107,336	6.1
DRESSER-RAND	2	400	65,000	13,800	175	$136,000	$87,000	$58,000	$446,921	$146,802	$97,629	NONE	$691,352	163	$102,132	6.8

COGENERATION QUOTE SUMMARY AND ANALYSIS

EMC ENGINEERS, INC.
PROJ. #____ PROJECT ____
SHEET NO. 86 OF 102
CALCULATED BY ____ DATE ____
CHECKED BY ____ DATE ____
SUBJECT ____

HOLSTON COGENERATION FACILITY
ONE-LINE DIAGRAM





EMC ENGINEERS, INC.
PROJ. #_____ PROJECT _____
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COGEN FACILITY
120V LOADS, MOTOR LOADS

SF = (12'x30') = 360 SQUARE FEET

PROJ. #______ PROJECT ______
SHEET NO. ______ OF ______
CALCULATED BY______ DATE______
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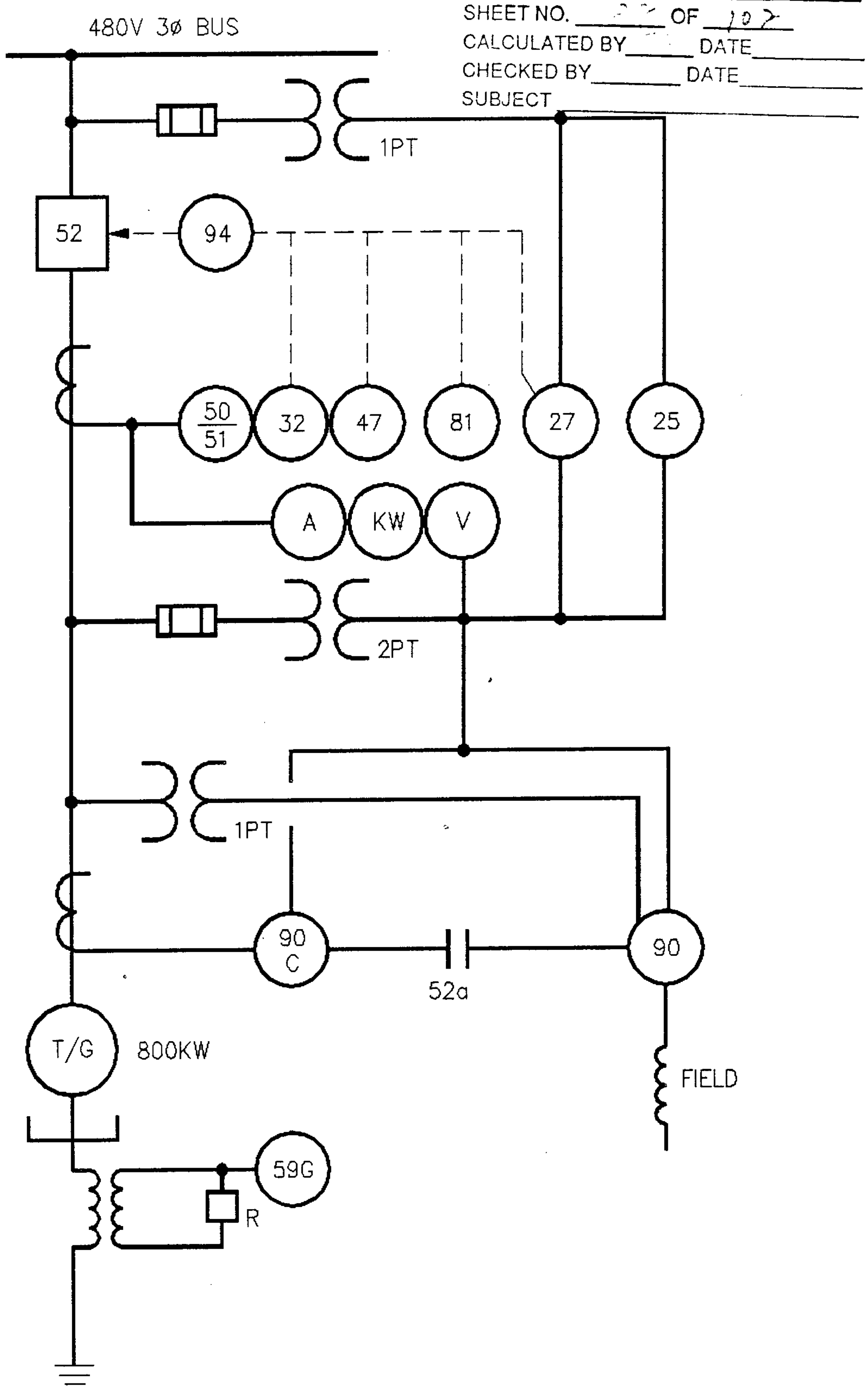
SUBJECT



SYNCHRONOUS GENERATOR PROTECTIVE RELAYING

FIGURE 7-6. COGENERATION PROTECTIVE RELAYING ONE-LINE DIAGRAM

LEGEND

25	Synchronizing relay for synchronous generation. Speed acceptor for induction generation (± 5% of synchronous speed) (mechanical).
27	Undervoltage, ≥ 80%, ≤ 0.5 sec., or time undervoltage, 90% ≤ 0.5 sec. at V=0, 1/phase.
32	Reverse power.
47/60	Phase sequence and voltage balance.
50/51	Instantaneous and time overcurrent, 1/phase.
50/51V	Voltage controlled time overcurrent with instantaneous, 1/phase.
50/51N	Instantaneous and time residual overcurrent.
52	Circuit breaker.
59	Overvoltage, ≤ 115%, ≤ 0.1 sec.
59G	Ground overvoltage (generator side).
59N	Ground overvoltage (utility side).
81-0	Overfrequency, ≤ 63Hz, ≤ 0.5 sec.
81-U	Underfrequency, ≥ 57Hz, ≤ 0.5 sec.
94	Tripping relay.
WH	Watt hour meter.
S.A.	Surge arrestor.

EMC ENGINEERS, INC.
PROJ. #_____ PROJECT _____
SHEET NO. 90 OF 102
CALCULATED BY _____ DATE _____
CHECKED BY _____ DATE _____
SUBJECT _____

ENGINEERS OPINION OF PROBABLE COST

Project	Holston Army Ammunition Plant Limited Energy Studies – DACA01–91–D–0032	SHEET 1 OF 1
		DATE PREPARED 01/21/92
Engineer	EMC Engineers, Inc – PN# 3102–002 Denver, CO	Estimator
Description	COGENERATION SYSTEM COST <COGNCOST>	Checked by

Description	Quantity: No. Units	Quantity: Unit Meas.	Material: Per Unit	Material: Total	Labor: Hours Per Unit	Labor: Hourly Rate	Labor: Total	Total Cost
TURBINE/GENERATOR PACKAGE	1	LS	$238,456.00	$238,456				$238,456
SYSTEM SUPPORT EQUIPMENT	1	LS	$95,874.00	$95,874				$95,874
ADMIN AREA STEAM MAIN	1	LS	$87,444.00	$87,444				$87,444
ELECTRICAL	1	LS	$63,760.00	$63,760				$63,760
SUBTOTAL				$485,534				$485,534
OVERHEAD & BOND	0.16			$77,685				$77,685
SUBTOTAL				$563,219				$563,219
PROFIT	0.1			$56,322				$56,322
SUBTOTAL				$619,541				$619,541
CONTINGENCY	0.2			$123,908				$123,908
TOTAL ESTIMATED COST				$743,450				$743,450

ENGINEERS OPINION OF PROBABLE COST

Project	Holston Army Ammunition Plant Limited Energy Studies – DACA01-91-D-0032	SHEET 1 OF 1
		DATE PREPARED 01/17/92
Engineer	EMC Engineers, Inc – PN# 3102-002 Denver, CO	Estimator
Description	TURBINE/GENERATOR <TURBCOST>	Checked by

Description	Quantity		Material		Labor			Total Cost
	No. Units	Unit Meas.	Per Unit	Total	Hours Per Unit	Hourly Rate	Total	
TURBINE/GENERATOR SET	1	EA	$227,580.00	$227,580	40	$21.90	$876	$228,456
FREIGHT	1	LS	$5,000.00	$5,000				$5,000
START-UP	1	LS	$5,000.00	$5,000				$5,000
SUBTOTAL				$237,580			$876	$238,456
OVERHEAD & BOND	0.16			$38,013			$140	$38,153
SUBTOTAL				$275,593			$1,016	$276,609
PROFIT	0.1			$27,559			$102	$27,661
SUBTOTAL				$303,152			$1,118	$304,270
CONTINGENCY	0.2			$60,630			$224	$60,854
TOTAL ESTIMATED COST				$363,782			$1,341	$365,124

ENGINEERS OPINION OF PROBABLE COST

Project	Holston Army Ammunition Plant Limited Energy Studies – DACA01-91-D-0032	SHEET 1 OF 1 DATE PREPARED 01/13/92
Engineer	EMC Engineers, Inc – PN# 3102-002 Denver, CO	Estimator
Description	COGENERATION SYSTEM SUPPORT EQUIPMENT (SYSCOST)	Checked by

Description	Quantity		Material		Labor			Total Cost
	No. Units	Unit Meas.	Per Unit	Total	Hours Per Unit	Hourly Rate	Total	
PRE-ENGINEERED BUILDING	360	SF	$6.30	$2,268	0.17	$21.90	$1,340	$3,608
>STEEL PIPE, A-53, SCH 40<								
6 IN WITH CL 300 WLD NK FLGS	160	LF	$34.00	$5,440	0.96	$21.90	$3,364	$8,804
10 IN WITH CL300 WLD NK FLGS	140	LF	$43.00	$6,020	1.5	$21.90	$4,599	$10,619
>STEEL PIPE, A-53, SCH 80<								
1 IN WITH CL 300 WLD NK FLGS	150	LF	$1.60	$240	0.2	$21.90	$657	$897
>PIPE INSULATION, FIBERGLASS<								
1 IN, 2 IN THK 500 DEG W/ ASJ	150	LF	$3.60	$540	0.08	$21.90	$263	$803
6 IN, 2 IN THK 500 DEG W/ ASJ	160	LF	$6.50	$1,040	0.16	$21.90	$561	$1,601
10 IN, 2 IN THK 500 DEG W/ ASJ	140	LF	$9.60	$1,344	0.229	$21.90	$702	$2,046
>GATE VALVE, CL 300<								
2 IN FLANGED, STEEL BODY	4	EA	$615.00	$2,460	1.081	$21.90	$95	$2,555
3 IN FLANGED, STEEL BODY	2	EA	$1,700.00	$3,400	4	$21.90	$175	$3,575
6 IN FLANGED, STEEL BODY	3	EA	$2,025.00	$6,075	8.276	$21.90	$544	$6,619
16 IN FLANGED, STEEL BODY	1	EA	$14,300.00	$14,300	26.667	$21.90	$584	$14,884
GATE VALVE, CL 150								
2 IN FLANGED, STEEL BODY	7	EA	$475.00	$3,325	1	$21.90	$153	$3,478
4 IN FLANGED, STEEL BODY	4	EA	$825.00	$3,300	5.333	$21.90	$467	$3,767
10 IN FLANGED, STEEL BODY	1	EA	$3,175.00	$3,175	10.909	$21.90	$239	$3,414
>STM TRAP W/STRNR & BLO-DN<								
3/4 IN, CL 600 FLANGED	3	EA	$490.00	$1,470	0.8	$21.90	$53	$1,523
3/4 IN, CL 150 THREADED	2	EA	$203.00	$406	0.4	$21.90	$18	$424
>PRV, PILOT-OPERATED<								
3 IN FLANGED	1	EA	$1,700.00	$1,700	4	$21.90	$88	$1,788
4 IN FLANGED	1	EA	$2,000.00	$2,000	4	$21.90	$88	$2,088
REDUCER, ECC, 10X4	2	EA	$70.00	$140	8	$21.90	$350	$490
6 IN PSV W/ DRIP PAN ELBOW	1	EA	$1,500.00	$1,500	16	$21.90	$350	$1,850
PRESSURE GAUGE ASSY, 3.5 IN	10	EA	$60.00	$600	0.6	$21.90	$131	$731
THERMOMETER AND WELL	6	EA	$270.00	$1,620	0.6	$21.90	$79	$1,699
PIPE SUPPORT	1	LS	$2,500.00	$2,500	82	$21.90	$1,796	$4,296
PIPE ANCHORS & GUIDES	2	EA	$230.00	$460	7.5	$21.90	$329	$789
STEAM TURBINE/GENERATOR SET	1	EA						
DESUPERHEATER	1	EA	$10,000.00	$10,000	6	$21.90	$131	$10,131
START-UP SYSTEMS	1	LS			60	$42.00	$2,520	$2,520
DEMOLITION	1	LS			40	$21.90	$876	$876
SUBTOTAL				$75,323			$20,551	$95,874
OVERHEAD & BOND	0.16			$12,052			$3,288	$15,340
SUBTOTAL				$87,375			$23,839	$111,214
PROFIT	0.1			$8,737			$2,384	$11,121
SUBTOTAL				$96,112			$26,223	$122,335
CONTINGENCY	0.2			$19,222			$5,245	$24,467
TOTAL ESTIMATED COST				$115,335			$31,467	$146,802

ENGINEERS OPINION OF PROBABLE COST

Project	Holston Army Ammunition Plant Limited Energy Studies – DACA01-91-D-0032	SHEET 1 OF 1	DATE PREPARED 01/13/92
Engineer	EMC Engineers, Inc – PN# 3102-002 Denver, CO	Estimator	
Description	ADMIN AREA DISTRIBUTION	Checked by	

Description	Quantity No. Units	Quantity Unit Meas.	Material Per Unit	Material Total	Labor Hours Per Unit	Labor Hourly Rate	Labor Total	Total Cost
6 IN WLDD STL PIPE, SCHED 40	1700	LF	$14.00	$23,800	0.587	$21.90	$21,854	$45,654
INSULATION, 500 DEG FIBERGLAS	1700	LF	$6.50	$11,050	0.16	$21.90	$5,957	$17,007
6 IN GATE VALVE, CL 300 FLGD	2	EA	$2,025.00	$4,050	8.276	$21.90	$362	$4,412
DRIP & TRAP ASSY W/ DRY WELL	2	EA	$620.00	$1,240	17.5	$21.90	$767	$2,007
PIPE ANCHOR ASSY & CONC PIER	2	EA	$230.00	$460	7.5	$21.90	$329	$789
PIPE SUPPORT ASSY AND PIER	86	EA	$105.00	$9,030	3.7	$21.90	$6,969	$15,999
PIPE GUIDE ASSY & CONC PIER	4	EA	$230.00	$920	7.5	$21.90	$657	$1,577
SUBTOTAL				$50,550			$36,894	$87,444
OVERHEAD & BOND	0.16			$8,088			$5,903	$13,991
SUBTOTAL				$58,638			$42,797	$101,435
PROFIT	0.1			$5,864			$4,280	$10,143
SUBTOTAL				$64,502			$47,077	$111,578
CONTINGENCY	0.2			$12,900			$9,415	$22,316
TOTAL ESTIMATED COST				$77,402			$56,492	$133,894

ENGINEERS OPINION OF PROBABLE COST

Project	Holston Army Ammunition Plant Limited Energy Studies – DACA01-91-D-0032	SHEET 1 OF 1 DATE PREPARED 01/17/92
Engineer	EMC Engineers, Inc – PN# 3102-002 Denver, CO	Estimator G. BAIRD
Description	ELECTRICAL INSTALLATION COGENERATION FACILITY	Checked by

Description	Quantity		Material		Labor			Total Cost
	No. Units	Unit Meas.	Per Unit	Total	Hours Per Unit	Hourly Rate	Total	
FUSED DISCONNECT SWITCH	1	EA	$103.00	$103	2.5	$16.19	$40	$143
3 PH., 3W, 30A, 600V								
TRANSFORMER, 3 PH., 7.5KVA, DR	1	EA	$525.00	$525	11.43	$16.19	$185	$710
480V/208Y120								
LIGHTING PANEL, 100A MAIN BKR.	1	EA	$623.00	$623	6.67	16.19	$108	$731
20 CKT, NEMA 3R ENCL.								
MANUAL MOTOR STARTER, SIZE 0	2	EA	$137.00	$274	1.45	$16.19	$47	$321
MOTOR CIRCUIT INSTALLATION								
CONDUIT, 3/4" EMT	60	LF	$0.47	$28	0.062	$16.19	$60	$88
WIRE, 3#12+#12G EA. CKT.	2.4	CLF	$6.70	$16	0.727	$16.19	$28	$44
LIGHTING, FLUORESCENT, 120V	7	EA	$60.00	$420	1.4	$16.19	$159	$579
INDUSTRIAL TYPE 2F40CW FIXT.								
EXIT LIGHTING, W/ EMERGENCY	2	EA	$150.00	$300	1.4	$16.19	$45	$345
BATTERY BACKUP FEATURE								
EXTERIOR LIGHTING, 120V FIXT.	2	EA	$50.00	$100	1	$16.19	$32	$132
RECEPTACLE OUTLETS, 120V, 20A	4	EA	$50.00	$200	1.25	$16.19	$81	$281
INCL. SURFACE MOUNTING BOX								
LIGHTING & RECPT INSTALLATION								
CONDUIT, 3/4" EMT	160	LF	$0.47	$75	0.062	$16.19	$161	$236
WIRE, 2#12+#12G	4.8	CLF	$6.70	$32	0.727	$16.19	$56	$89
INSTALL BUILDING GROUNDING								
GROUND RODS, 8' LONG, 5/8" DIA	2	EA	$390.00	$780	3	$16.19	$97	$877
GROUND GRID, 2/0 BARE CU WIRE	1	CLF	$100.80	$101	2.2	$16.19	$36	$136
GROUND CONNECT'S, CADWELD	6	EA	$7.50	$45	1.14	$16.19	$111	$156
SWITCHGEAR INSTALLATION								
2000A MAIN LUG SWITCHGEAR	1	EA	$15,000.00	$15,000	24	$16.19	$389	$15,389
W/ 2-1200A NONFUSIBLE DISC.								
MODIFY TRANSFORMER PAD FOR	1	EA	$1,000.00	$1,000	24	$16.19	$389	$1,389
SWITCHGEAR INSTALLATION								
FEEDER INSTALLATION FROM								
SWITCHGEAR IN COGEN BLDG								
EXCAVATE TRENCH FOR DUCTS	115	LF			0.75	12.86	$1,109	$1,109
UNDERGROUND DUCT, RGS 3" DIA	230	LF	$7.10	$1,633	2.52	$16.19	$9,384	$11,017
700 MCM CABLE, 600V, XHHW	6.9	CLF	$735.00	$5,072	185	$16.19	$20,667	$25,738
BACKFILL TRENCH OVER DUCTS	115	LF			1.04	$16.19	$1,936	$1,936
CABLE INSTALLATION W/ LUGS	12	EA	$43.50	$522	0.5	$16.19	$97	$619
BUS DUCT CONNECTION FROM	1	EA	$1,500.00	$1,500	12	$16.19	$194	$1,694
1500KVA XFMR TO SWITCHGEAR								
SUBTOTAL				$28,349			$35,411	$63,760
OVERHEAD & BOND	0.16			$4,536			$5,666	$10,202
SUBTOTAL				$32,885			$41,077	$73,962
PROFIT	0.1			$3,288			$4,108	$7,396
SUBTOTAL				$36,173			$45,185	$81,358
CONTINGENCY	0.2			$7,235			$9,037	$16,272
TOTAL ESTIMATED COST				$43,408			$54,222	$97,629

PRE-ENGINEERED STEEL BUILDING
1992 MEANS 051-235

Building shell above foundation w/26 ga. colored roofing and siding/SF bare:

$3	Material
$0.90	Labor
$0.70	Equipment

∴ 4.60 x 30 x 12 (1080 + 324 + 252)	= 1,660	
Double leaf doors, 6'x7' (495 + 200)	= 695	
	$2,355	say $2400

Floor slab-on-grade, direct chute placed (5 cy):	8.35 labor; 0.59 equipment	
Concrete finishing, float finish (360 SF)	0.25 labor; 0.05 equipment	
Concrete ready mix, 3000 psi (5 cy)	52.30 material = $262	say $270

Building Totals:

Material:	1080 + 495 + 270	= 1850		1850
Labor:	324 + 200 + 42 + 90	= 660 + 54	=	714
Equipment:	252 + 3 + 18	= 273 + 84	=	357
	Total Building	= 2783		2921

Site preparation (40 sy) — 0.67 labor; 1.05 equipment
(x 2 for small scale of job)

Labor		= 27		54
Equipment		= 42		84
	Total	= 69 x 2	=	138

Total Building: 2783 + 138 = 2921 — say $3000

$3000 /360 SF = 8.33 $/SF say 10.00 $/SF w/ elec. & mech., not including O&P

∴	3600
15% OH	540
	4140
10% O&P	414
	4554

say $4600 for building including O&P (12.78 $/SF).

EMC ENGINEERS, INC.
PROJ. #_____ PROJECT ________
SHEET NO. _____ OF _____
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PIPE SUPPORT FRAMING
1992 MEANS (051 110) p. 37

6' steam @ 20 lb/LF x 100 LF = 2000 lb x 0.55M & 0.17L = 1100 + 340	=	1,440
10" steam @ 40 lb/LF x 60 LF = 2400 lb x 0.50 M & 0.15L = 1200 _ 360	=	1,560
		3,000
Plus Pipe routers, plates, etc. (Allow)		1,000
Total Pipe Supports (LS)		4,000

EMC ENGINEERS, INC.
PROJ. #______ PROJECT __________
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SUBJECT ______________

EMC ENGINEERS, INC.
PROJ. #_____ PROJECT _____
SHEET NO. _____ OF _____
CALCULATED BY _____ DATE _____
CHECKED BY _____ DATE _____
SUBJECT _____

LIFE CYCLE COST ANALYSIS (INPUT DATA)

Base Case

Coal	2,086,488 MMBtu
Electricity	58,753,000 kWh

Option-1

Proposed System plus repair of existing system.

Coal 2,100,533 MMBtu
Savings = -14,045 MBtu

Electricity 49,003,620 kWh
Savings = 9,749,880 kWh
x 0.003413 MMBtu/kWh = 33,276 MMBtu.

Investment

Proposed system	$743,450
Repair existing	5,000
	$748,450

Maintenance $ 52,796

Option-2

Proposed system only.

Coal 2,100,533 MMBtu
Savings = -14,045 MMBtu

Electricity 51,631,600 kWh
Savings = 24,307 MMBtu

Investment $743,450

Maintenance $52,796

EMC ENGINEERS, INC.
PROJ. #______ PROJECT ______
SHEET NO. 99 OF 102
CALCULATED BY ______ DATE ______
CHECKED BY ______ DATE ______
SUBJECT ______

COGENERATION ANALYSIS OF RECOMMENDED SYSTEM

BLC	1,865,000		SPACE LOAD COEF
UA	22,622		DISTRIBUTION LOSS COEF
PROC	106,982	LBM/HR	PROCESS DEMAND
PROC300	47,462	LBM/HR	300 PSIG DEMAND
DHNOW	1,028	BTU/LBM	300 PSIG ENERGY CONTENT
DHNEW	982	BTU/LBM	EXIT STEAM ENERGY CONTENT
INB	16%		IN PLANT STEAM
TSTM	430		STEAM TEMP
ASR	83	LBM/KW/HR	TURBINE STEAM RATE
SIZE	67,700	LBM/HR	TURBINE SIZE
BOILEFF	72.00%		
COAL$	1.2500	$/MBTU	
KW$	9.5000	$/KW	
KWH$	0.0159	$/KWH	

		DEGREE DAYS	AMBIENT TEMP (F)	LOW PRES PROCESS (LBM/HR)	300 psig PROCESS (LBM/HR)	HEATING LOAD (LBM/HR)	DSTRB LOSS (LBM/HR)	STEAM DEMAND (LBM/HR)	COGEN STEAM (LBM/HR)	ELECTRIC USAGE (KWH)	ELECTRIC DEMAND (KW)	AVG DEMAND (KW)	TURBINE STEAM (LBM/HR)
Jan	31	930	35	62,308	47,462	56,976	9,099	175,845	128,383	5,545,500	9,235	7,454	67,700
Feb	28	759	38	62,308	47,462	51,481	9,030	170,282	122,820	4,716,000	8,926	7,018	67,700
Mar	31	580	46	62,308	47,462	35,533	8,846	154,149	106,687	4,619,000	8,793	6,208	67,700
Apr	30	375	56	62,308	47,462	23,740	8,616	142,126	94,664	5,047,000	8,815	7,010	67,700
May	31	111	64	62,308	47,462	6,800	8,431	125,002	77,540	4,513,500	8,650	6,067	67,700
Jun	30	10	72	62,308	47,462	633	8,247	118,650	71,188	4,621,000	8,904	6,418	67,700
Jul	31	0	75	62,308	47,462	0	8,178	117,948	70,486	4,944,500	8,948	6,646	67,700
Aug	31	0	74	62,308	47,462	0	8,201	117,971	70,509	4,618,000	8,992	6,207	67,700
Sep	30	35	69	62,308	47,462	2,216	8,316	120,302	72,840	4,925,000	9,340	6,840	67,700
Oct	31	263	57	62,308	47,462	16,112	8,593	134,475	87,013	4,970,500	8,909	6,681	67,700
Nov	30	564	46	62,308	47,462	35,705	8,846	154,321	106,859	5,012,000	9,045	6,961	67,700
Dec	31	831	38	62,308	47,462	50,910	9,030	169,711	122,249	5,221,500	9,092	7,018	67,700
Yr		4,458	56	62,308	47,462	23,342	8,620	141,732	94,270	58,753,500	8,971	6,711	812,400

EMC ENGINEERS, INC.
PROJ. #______ PROJECT ______
SHEET NO. 100 OF 1__
CALCULATED BY ____ DATE 1/__/97
CHECKED BY ______ DATE ______
SUBJECT ______

COGENERATION ANALYSIS OF RECOMMENDED SYSTEM

ECONOMIC ANALYSIS							
BASE ENERGY COST	4,576,113						
TURBINE SIZE (LBM/HR)	120,000	20,000	40,000	60,000	80,000	100,000	120,000
ANNUAL ENERGY COST	4,388,176	4,493,046	4,449,075	4,405,104	4,378,030	4,380,408	4,395,395
ENERGY COST SAVINGS	187,937	83,067	127,038	171,009	198,083	195,705	180,718
CAPITAL COST	737,601	306,128	413,690	505,519	588,423	665,267	737,601
SIMPLE PAYBACK	3.9	3.7	3.3	3.0	3.0	3.4	4.1

	POWER PRODUCE (KW)	DESUPER STEAM IN (LBM/HR)	CHP DEMAND (LBM/HR)	IN PLANT STEAM (LBM/HR)	BOILER STEAM (LBM/HR)	BOILER STEAM (MBTU)	COAL USAGE (MBTU)	DEMAND BILLED (KW)	ELECTRIC PURCHASE (KWH)	COAL PURCHASE ($)	DEMAND CHARGES ($)	KWH CHARGES ($)	ELECTRIC CHARGES ($)	TOTAL CHARGES ($)
Jan	813	57,968	173,130	33,963	207,093	158,391	219,988	8,423	4,940,833	$274,985	$80,014	$78,312	$159,500	$434,485
Feb	813	52,654	167,816	32,921	200,736	138,672	192,600	8,113	4,169,849	$240,750	$77,075	$66,092	$144,342	$385,091
Mar	813	37,243	152,405	29,898	182,302	139,431	193,654	7,981	4,014,333	$242,067	$75,816	$63,627	$140,617	$382,684
Apr	813	25,757	140,919	27,644	168,564	124,764	173,283	8,003	4,461,838	$216,604	$76,026	$70,720	$147,920	$364,524
May	813	9,400	124,562	24,436	148,997	113,958	158,275	7,837	3,908,833	$197,843	$74,452	$61,955	$137,581	$335,424
Jun	813	3,332	118,494	23,245	141,739	104,910	145,708	8,091	4,035,838	$182,135	$76,865	$63,968	$142,008	$324,143
Jul	813	2,661	117,823	23,114	140,937	107,793	149,713	8,135	4,339,833	$187,141	$77,285	$68,786	$147,246	$334,387
Aug	813	2,683	117,845	23,118	140,963	107,813	149,741	8,179	4,013,333	$187,176	$77,705	$63,611	$142,490	$329,666
Sep	813	4,910	120,072	23,555	143,627	106,307	147,648	8,527	4,339,838	$184,561	$81,011	$68,786	$150,971	$335,532
Oct	813	18,449	133,611	26,211	159,822	122,237	169,773	8,097	4,365,833	$212,217	$76,918	$69,198	$147,290	$359,507
Nov	813	37,407	152,569	29,930	182,498	135,078	187,608	8,232	4,426,838	$234,510	$78,203	$70,165	$149,543	$384,053
Dec	813	52,108	167,270	32,814	200,084	153,030	212,542	8,279	4,616,833	$265,678	$78,650	$73,177	$153,000	$418,678
Yr			140,543	27,571	168,114	1,512,384	2,100,533		51,634,028	2,625,667	930,020	818,399	1,762,509	4,388,176

LIFE CYCLE COST ANALYSIS SUMMARY
ENERGY CONSERVATION INVESTMENT PROGRAM (ECIP)

LOCATION:	HOLSTON AAP	REGION:	4
PROJ. NO. & TITLE:	DACA01-91-D-0032 LIMITED ENERGY STUDIES		
DISCRETE PORTION:	COGENERATION		
FISCAL YEAR:	91	ECONOMIC LIFE	25
ANALYSIS DATE:	04-Aug-92	PREPARED BY: D JONES	

1 INVESTMENT

A.	CONSTRUCTION COST		=	$743,450
B.	SIOH COST	(5.5% of 1A)	=	$40,890
C.	DESIGN COST	(6.0% of 1A)	=	$44,607
D.	SALVAGE VALUE		=	$0
E.	TOTAL INVESTMENT	(1A + 1B +1C +1D − 1E)	=	$828,947

2 ENERGY SAVINGS (+) / COST (−)

	FUEL TYPE	FUEL COST $/MBTU (1)	SAVINGS MBTU/YR (2)	ANNUAL $ SAVINGS (3)	DISCOUNT FACTOR (4)	DISCOUNTED SAVINGS (5)
A.	ELEC	$4.67	24,307	$113,514	15.61	$1,771,949
B.	DIST		0	$0	0.00	$0
C.	RESID		0	$0	0.00	$0
D.	NAT GAS		0	$0		$0
E.	COAL	$1.25	(14,045)	($17,556)	16.06	($281,953)
F.	TOTAL ENERGY SAVINGS		10,262	$95,957		$1,489,995

3 NON-ENERGY SAVINGS (+) / COST (−)

A. ANNUAL RECURRING

	ANNUAL $	DISCOUNT FACTOR	DISCOUNTED SAVINGS
ADDED MAINTENANCE COST	($6,400)	14.53	($92,992)
ELECTRIC DEMAND SAVINGS 813 KW * $9.50/KW/MTH * 12 MTHS =	$92,682	14.53	$1,346,669
TOTAL SAVINGS (+) / COST (−)	$86,282		$1,253,677

B. NON-RECURRING (+/−)

ITEM	YEAR OF OCCURRENCE	ANNUAL $	DISCOUNT FACTOR	DISCOUNTED SAVINGS
a.		$0	0.00	$0
b.		$0	0.00	$0
c.		$0	0.00	$0
TOTAL SAVINGS (+) / COST (−)		$0		$0

C. TOTAL NON ENERGY DISCOUNTED SAVINGS (3A + 3B) — $1,253,677

D. PROJECT NON-ENERGY QUALIFICATION TEST
NON ENERGY SAVINGS % (3C / (3C + 2F)) — 46%

4 FIRST YEAR DOLLAR SAVINGS (+) / COSTS (−)	$182,239	
5 TOTAL NET DISCOUNTED SAVINGS		$2,743,673
6 DISCOUNTED SAVINGS-TO-INVESTMENT RATIO (SIR)		2.39
7 SIMPLE PAYBACK (YEARS)		4.55

LIFE CYCLE COST ANALYSIS SUMMARY
ENERGY CONSERVATION INVESTMENT PROGRAM (ECIP)

LOCATION:	HOLSTON AAP	REGION:	4
PROJ. NO. & TITLE:	DACA01-91-D-0032 LIMITED ENERGY STUDIES		
DISCRETE PORTION:	REPAIR EXISTING COGENERATION SYSTEM		
FISCAL YEAR:	91	ECONOMIC LIFE	25
ANALYSIS DATE:	05-Aug-92	PREPARED BY:	D JONES

1 INVESTMENT

A.	CONSTRUCTION COST	=	$5,000
B.	SIOH COST	(5.5% of 1A) =	$275
C.	DESIGN COST	(6.0% of 1A) =	$300
D.	SALVAGE VALUE	=	$0
E.	TOTAL INVESTMENT	(1A + 1B +1C +1D − 1E) =	$5,575

2 ENERGY SAVINGS (+) / COST (−)

	FUEL TYPE	FUEL COST $/MBTU (1)	SAVINGS MBTU/YR (2)	ANNUAL $ SAVINGS (3)	DISCOUNT FACTOR (4)	DISCOUNTED SAVINGS (5)
A.	ELEC	$4.67	8,969	$41,887	15.61	$653,855
B.	DIST		0	$0	0.00	$0
C.	RESID		0	$0	0.00	$0
D.	NAT GAS		0	$0		$0
E.	COAL	$1.25	0	$0	16.06	$0
F.	TOTAL ENERGY SAVINGS		8,969	$41,887		$653,855

3 NON-ENERGY SAVINGS (+) / COST (−)

A. ANNUAL RECURRING

ADDED MAINTENANCE COST	($6,400)	14.53	($92,992)
ELECTRIC DEMAND SAVINGS 300 KW * $9.50/KW/MTH * 12 MTHS =	$34,200	14.53	$496,926
TOTAL SAVINGS (+) / COST (−)	$27,800		$403,934

B. NON-RECURRING (+/−)

ITEM	YEAR OF OCCURRENCE			
a.		$0	0.00	$0
b.		$0	0.00	$0
c.		$0	0.00	$0
TOTAL SAVINGS (+) / COST (−)		$0		$0

C. TOTAL NON ENERGY DISCOUNTED SAVINGS (3A + 3B) $403,934

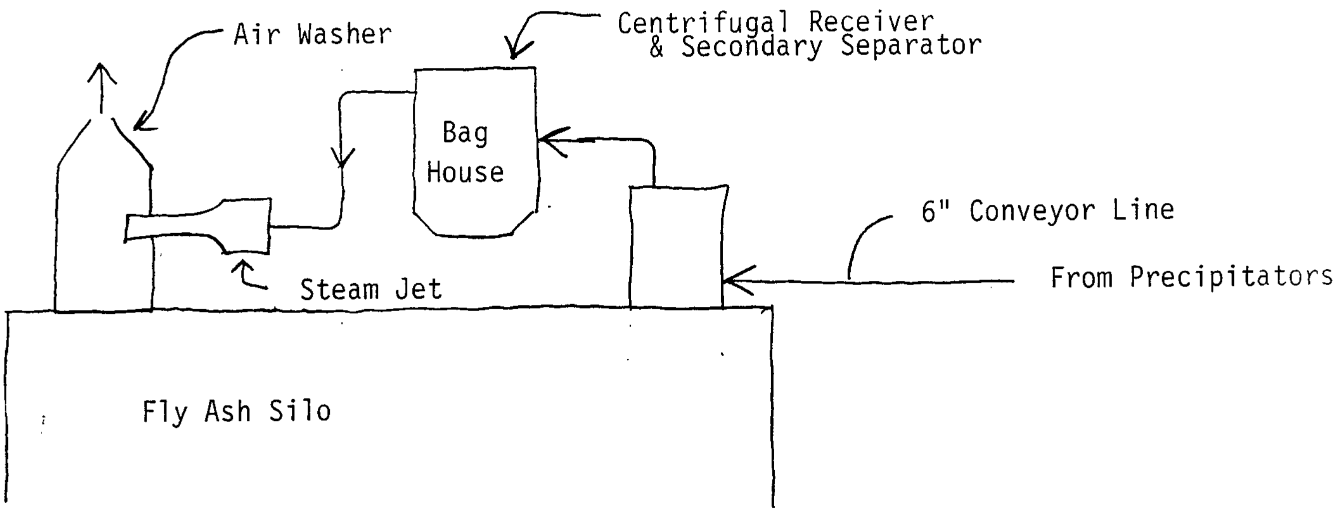
D. PROJECT NON-ENERGY QUALIFICATION TEST
NON ENERGY SAVINGS % (3C / (3C + 2F)) 38%

4 FIRST YEAR DOLLAR SAVINGS (+) / COSTS (−)	$69,687	
5 TOTAL NET DISCOUNTED SAVINGS		$1,057,789
6 DISCOUNTED SAVINGS-TO-INVESTMENT RATIO (SIR)		155.99
7 SIMPLE PAYBACK (YEARS)		0.08

APPENDIX D

VACUUM PUMPS ANALYSIS
AREAS A & B

EXISTING FLY ASH CONVEYOR SYSTEM



- Existing system operates 4 hours/day with steam jet operating 75% of the time.
- Ash lift height is 65 feet.
- Maximum horizontal distance is 100 feet.
- Hisotircal data indicates that the Area-B CHP generates an average 50 cy. Weight of fly ash is 50 lbm/ft^3.

$$\frac{50\,cy}{day} x \frac{27\,ft^3}{cy} x \frac{50 lbm/ft^3}{day/3\,hrs} = 22{,}500\; lbm/hr.$$

- National conveyor estimates vacuum requirements at 1475 cfm with a 10.2" Hg vacuum.

EMC ENGINEERS, INC.
PROJ. #_____ PROJECT _____
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STEAM ENERGY SAVINGS

Hourly Steam Usage ~ 7,500 lb/hr

Area-A

$$Daily\ Usage = \begin{array}{l} 1.5\frac{hrs}{day}\ x\ 9{,}822\frac{lb}{hr} = 14{,}733\ lb/day \\ x\ 1{,}094\frac{Btu}{lbm}\ x\ 365\ days = \mathbf{5{,}883}\ MBtu/yr \end{array}$$

Area-B

$$Daily\ Usage = \begin{array}{l} 3.0\ \frac{hrs}{day}\ x\ 7{,}500\frac{lb}{hr} = 22{,}500\ lb/day \\ x\ 1{,}074\frac{Btu}{lbm}\ x\ 365\ days = \mathbf{8{,}820}\ MBtu/yr \end{array}$$

ADDED ELECTRICITY USE

Blower: 65 Amps @ 460 V

kW = $\sqrt{3}$ VI = $\sqrt{3}$ (460 V) (65 A) = 51.8 kW.

Area-A

$$51.8\ kW\ x\ 1.5\ \frac{hrs}{day}\ x\ 365\ \frac{day}{yr} = 28{,}360.5\ \frac{kWh}{yr}$$
$$= \mathbf{96.8}\ MBtu/yr.$$

Area-B

$$51.8\ kW\ x\ 3.0\ \frac{hrs}{day}\ x\ 365\ \frac{day}{yr} = 56{,}721.5\ \frac{kWh}{yr}$$
$$= \mathbf{193.5}\ MBtu/yr.$$

EMC ENGINEERS, INC.
PROJ. #_____ PROJECT _____
SHEET NO. 3 OF 5
CALCULATED BY _____ DATE _____
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PROPOSAL DESCRIPTION For: REPTEK

VACUUM BLOWER
Vacuum Blower pkg, rotary pos displ type with standard shaft seals, sized to handle 1475 ICFM at 10.2"Hg. Package includes Sutorbilt 713-4500 @ 2018 RPM (82% max), req 43 BHP @ 70°F & 38% RH @ free air inlet
Max rating: 1851 ICFM, 2450 RPM, 16.0" Hg.
Assembled package includes the following:

- Non-Elevated Steel Base
- V-Belt Drive & Steel Guard

- 8" Inlet silencer, cstl, RISY type

- 8" Dischg silencer, cstl, SDY type
- 8" Dischg check valve, cstl const
- Vacuum relief valve, spring type (set @ 16.0"Hg, req. 48 BHP)
- Lot accessory piping
- 8" Instrument spool, cstl, including:
- Vacuum gauge

BLOWER MOTOR
Blower motor, 50 HP, 1800 RPM with (65 AMPS) sliding base, equipped as follows:

- 460 volt, 3 phase, 60 hertz
- 1.15 Service factor
- Standard Efficiency
- Std duty construction
- TEFC enclosure
- 326 T Nema frame
- Standard factory tests

PRICE, F.O.B. SHIPPING POINT ------ \$12,968.00
EST. WT.- 2,274 LBS.

OPTIONS:

1- PRESSURE SWITCH (MEASURE ΔP ACROSS LINE FILTER).
PRICE, \$150.00

1-(or 2) LINE FILTER(S) w/ 8" FLANGED ENDS & SUPPORT LEGS, EST. WEIGHT 175 lbs.
PRICE, FOB SHIPPING POINT ... -- \$1,299.00 EA.

PROJ. #____	PROJECT ____
SHEET NO. 4	OF ____
CALCULATED BY ____	DATE ____
CHECKED BY ____	DATE ____
SUBJECT ~~PROPOSAL~~	

graham
Vacuum and Heat Transfer

EG# 145DEN91

FRY EQUIPMENT CO., INC.
2600 W. 2nd AVE., SUITE 7
DENVER, COLORADO 80219
PHONE: (303) 922-8442
FAX: (303) 922-8445

EMC ENGINEERS
2750 S. Wadsworth Blvd.
Denver, CO 80236

JOB: Holston Army Munitions Arsenal
LOCATION: Tennessee

ATTN: Mr. Ron Gerands

DATE: November 26, 1991

WE ARE PLEASED TO QUOTE ON EQUIPMENT AS FOLLOWS:

(1) Liquid Ring Vacuum Pump, Graham Model #1V8146-FRZ. Capacity of 1500 ACFM of dry air at 10.2" HgA or 259 M.M.HgA. Cast iron case, ductile iron rotors, 420 S.S. shaft, 420 S.S. packing glands, 100 HP TEFC motor, 720 RPM, 460/3/60, carbon steel baseplate.

PRICE: $39,810.00 Net

Note: Liquid Ring Pump requires a maxium of 40 GPM of seal water supply at 60 deg. F.

FRY EQUIPMENT CO., INC.
SUBMITTED BY:

Louis N. Grounds
Sales Engineer

TERMS: Net 30 days
DELIVERY: 20-22 weeks
WEIGHT: 6230 lbs.
F.O.B.: Batavia, NY

EMC ENGINEERS, INC.
PROJ. # ______ PROJECT ______
SHEET NO. 5 OF 5
CALCULATED BY ______ DATE ______
CHECKED BY ______ DATE ______
SUBJECT ______

Maintenance Costs

- Assume 2 men @ $15/hr.
- Replacement Filters: $150
- Replacement Time: 1 hour
- Cost/Replacement: $180
- Assume Replacement Every 200 Operating Hours

Area A

$$\frac{200 \text{ hrs}}{\text{Replacement}} \times \frac{1 \text{ Day}}{1.5 \text{ hrs}} = 133 \text{ Days/Replacement} \sim 4 \text{ Mon. Replacement}$$

= 3 Replacements/yr

Cost: 3 x $180 = $540 + 20% = $650/yr

Area B

$$\frac{200 \text{ hrs}}{\text{Replacement}} \times \frac{1 \text{ Day}}{3 \text{ hrs}} = 67 \text{ Days/Replacement} \sim 2 \text{ Mon. Replacement}$$

= 6 Replacements/yr

Cost: 6 x $180 = $1080 + 20% = $1300/yr

ENGINEERS OPINION OF PROBABLE COST

Project	Holston Army Ammunition Plant Limited Energy Studies - DACA01-91-D-0032	SHEET OF	DATE PREPARED 12/06/91
Engineer	EMC Engineers, Inc - PN# 3102-002 Denver, CO	Estimator	
Description	Replace steam extractor with vacuum blower	Checked by	

Description	Quantity No. Units	Quantity Unit Meas.	Material Per Unit	Material Total	Labor Hours Per Unit	Labor Hourly Rate	Labor Total	Total Cost
>>Demolition<<								
Removal of existing steam jet	1	EA			1	$16.89	$17	$17
Removal of air washer	1	EA			16	$16.89	$270	$270
>>Mechanical<<								
Lever Hoist	1	EA	$150.00	$150				$150
Vacuum Blower w/ 50 hp motor	1	EA	$12,968.00	$12,968	3	$16.89	$51	$13,019
6" pipe	15	LF	$13.54	$203	0.667	$16.89	$169	$372
6" elbows	2	EA	$30.00	$60	4.8	$16.89	$162	$222
6" welded flanges	4	EA	$37.00	$148	4.8	$16.89	$324	$472
Line Filter	1	EA	$1,299.00	$1,299	4	$16.89	$68	$1,367
Pressure switch	1	EA	$150.00	$150	1	$16.89	$17	$167
>>Electrical<<								
Conduit, 1-1/2"	350	LF	$2.85	$998	0.145	$16.19	$822	$1,819
Wire, #1 THW	12	CLF	$71.90	$863	1.5	$16.19	$291	$1,154
Starter, sz 3	1	EA	$922.00	$922	12.12	$16.19	$196	$1,118
>>Equipment Rental<<								
Crane	8	HR	$19.65	$157	1	$14.86	$119	$276
SUBTOTAL				$17,918			$2,506	$20,423
OVERHEAD & BOND	0.16			$2,867			$401	$3,268
SUBTOTAL				$20,784			$2,907	$23,691
PROFIT	0.1			$2,078			$291	$2,369
SUBTOTAL				$22,863			$3,197	$26,060
CONTINGENCY	0.2			$4,573			$639	$5,212
TOTAL ESTIMATED COST				**$27,435**			**$3,837**	**$31,272**

LIFE CYCLE COST ANALYSIS SUMMARY
ENERGY CONSERVATION INVESTMENT PROGRAM (ECIP)

LOCATION:	HOLSTON AAP	REGION:	4
PROJ. NO. & TITLE:	DACA01-91-D-0032 LIMITED ENERGY STUDIES		
DISCRETE PORTION:	AREA B VACUUM PUMP		
FISCAL YEAR:	91	ECONOMIC LIFE	25
ANALYSIS DATE:	16-Jul-92	PREPARED BY: D JONES	

1 INVESTMENT

A.	CONSTRUCTION COST	=	$31,272
B.	SIOH COST	(5.5% of 1A) =	$1,720
C.	DESIGN COST	(6.0% of 1A) =	$1,876
D.	SALVAGE VALUE	=	$0
E.	TOTAL INVESTMENT	(1A + 1B +1C +1D – 1E) =	$34,868

2 ENERGY SAVINGS (+) / COST (–)

	FUEL TYPE	FUEL COST $/MBTU (1)	SAVINGS MBTU/YR (2)	ANNUAL $ SAVINGS (3)	DISCOUNT FACTOR (4)	DISCOUNTED SAVINGS (5)
A.	ELEC	$4.67	(194)	($906)	15.61	($14,142)
B.	DIST		0	$0	0.00	$0
C.	RESID		0	$0	0.00	$0
D.	NAT GAS		0	$0		$0
E.	COAL	$1.25	8,820	$11,025	16.06	$177,062
F.	TOTAL ENERGY SAVINGS		8,626	$10,119		$162,919

3 NON-ENERGY SAVINGS (+) / COST (–)

A. ANNUAL RECURRING

	ANNUAL $	DISCOUNT FACTOR	DISCOUNTED SAVINGS
ADDED MAINTENANCE COST	($1,300)	14.53	($18,889)
ELECTRIC DEMAND SAVINGS			
0 KW * $9.50/KW/MTH * 12 MTHS =	$0	14.53	$0
TOTAL SAVINGS (+) / COST (–)	($1,300)		($18,889)

B. NON-RECURRING (+/–)

ITEM	YEAR OF OCCURRENCE			
a.		$0	0.00	$0
b.		$0	0.00	$0
c.		$0	0.00	$0
TOTAL SAVINGS (+) / COST (–)		$0		$0

C. TOTAL NON ENERGY DISCOUNTED SAVINGS (3A + 3B) ($18,889)

D. PROJECT NON-ENERGY QUALIFICATION TEST
NON ENERGY SAVINGS % (3C / (3C + 2F)) –13%

4 FIRST YEAR DOLLAR SAVINGS (+) / COSTS (–)	$8,819
5 TOTAL NET DISCOUNTED SAVINGS	$144,030
6 DISCOUNTED SAVINGS-TO-INVESTMENT RATIO (SIR)	4.13
7 SIMPLE PAYBACK (YEARS)	3.95

EMC ENGINEERS, INC.
PROJ. #____ PROJECT 310.-002
SHEET NO. 7 OF 7
CALCULATED BY DJ DATE 7/-/92
CHECKED BY____ DATE____
SUBJECT____

LIFE CYCLE COST ANALYSIS SUMMARY
ENERGY CONSERVATION INVESTMENT PROGRAM (ECIP)

LOCATION:	HOLSTON AAP	REGION:	4
PROJ. NO. & TITLE:	DACA01-91-D-0032 LIMITED ENERGY STUDIES		
DISCRETE PORTION:	AREA A VACUUM PUMP		
FISCAL YEAR:	91	ECONOMIC LIFE	25
ANALYSIS DATE:	16-Jul-92	PREPARED BY: D JONES	

1 INVESTMENT

A.	CONSTRUCTION COST	=	$31,272
B.	SIOH COST	(5.5% of 1A) =	$1,720
C.	DESIGN COST	(6.0% of 1A) =	$1,876
D.	SALVAGE VALUE	=	$0
E.	TOTAL INVESTMENT	(1A + 1B +1C +1D − 1E) =	$34,868

2 ENERGY SAVINGS (+) / COST (−)

	FUEL TYPE	FUEL COST $/MBTU (1)	SAVINGS MBTU/YR (2)	ANNUAL $ SAVINGS (3)	DISCOUNT FACTOR (4)	DISCOUNTED SAVINGS (5)
A.	ELEC	$4.67	(97)	($453)	15.61	($7,071)
B.	DIST		0	$0	0.00	$0
C.	RESID		0	$0	0.00	$0
D.	NAT GAS		0	$0		$0
E.	COAL	$1.25	5,883	$7,354	16.06	$118,101
F.	TOTAL ENERGY SAVINGS		5,786	$6,901		$111,030

3 NON-ENERGY SAVINGS (+) / COST (−)

A. ANNUAL RECURRING

ADDED MAINTENANCE COST	($650)	14.53	($9,445)
ELECTRIC DEMAND SAVINGS 0 KW * $9.50/KW/MTH * 12 MTHS =	$0	14.53	$0
TOTAL SAVINGS (+) / COST (−)	($650)		($9,445)

B. NON-RECURRING (+/−)

ITEM	YEAR OF OCCURRENCE			
a.		$0	0.00	$0
b.		$0	0.00	$0
c.		$0	0.00	$0
TOTAL SAVINGS (+) / COST (−)		$0		$0

C. TOTAL NON ENERGY DISCOUNTED SAVINGS (3A + 3B) ($9,445)

D. PROJECT NON-ENERGY QUALIFICATION TEST
NON ENERGY SAVINGS % (3C / (3C + 2F)) −9%

4 FIRST YEAR DOLLAR SAVINGS (+) / COSTS (−)	$6,251	
5 TOTAL NET DISCOUNTED SAVINGS		$101,586
6 DISCOUNTED SAVINGS-TO-INVESTMENT RATIO (SIR)		2.91
7 SIMPLE PAYBACK (YEARS)		5.58

EMC ENGINEERS, INC.
PROJ. #______ PROJECT ______
SHEET NO. 3 OF ______
CALCULATED BY ______ DATE ______
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APPENDIX E

INTERMEDIATE STEAM PRESSURE HEADER ANALYSIS

EMC ENGINEERS, INC.
PROJ. #______ PROJECT __________
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INTERMEDIATE STEAM PRESSURE HEADER

Existing Conditions:

Average steam production	161,816 lbm
Economizer (EWT)	229°F
Economizer (LWT)	285°F
Economizer (EAT)	480°F

Excess low pressure steam vented April through October (see boiler model).

Proposed Modification:

Increase backpressure on fan turbine and route exhaust to new feedwater heater.

Analysis:

Fan turbine rated at 550 hp and 21.6 lbm/hp at 5 psig.

Turbine casing rated for 75 psig.
Renozzling for 550 hp ⇒ 45.5 lbm/hp.

Turbine casing could be retested for 125 psig.
Renozzling for 550 hp ⇒ 92.7 lbm/hp.

Modify CHP model with new inputs and calculate fuel use. Assume $\varepsilon = 0.8$ for feedwater heater.

Header Pressure (psig)	Header Temp (°F)	Header Latent Enthalpy (Btu/lbm)	Turbine Steam Rate (lbm/hp)	Coal* Usage (MMBtu)	Coal Savings (MMBtu)
5	228	960	21.6	2,155,572	0
50	298	912	38.7	2,095,722	59,850
75	320	895	45.5	2,083,088	72,484
125	353	868	92.7	2,397,027	-241,455

*From boiler model.

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MANUFACTURERS' DATA ON STEAM RATES

Skinner Engine Company
Phone: 814/454-7103
Erie, Pennsylvania 16512

Model No. S-28-3
Serial No. 755T10148

Backpressure limited by the ability of exhaust casing to handle exit pressures.

Existing turbines are good for 75 psi only.

Replace nozzles:
25,000 lbm/hr, 550 hp, p_e=75 — 25,000/550 = 45.5 lbm/hr/hp

Rehydrotest case:
p_e = 125 psi, 550 hp, 51,000 lbm/hr — 51,000/550 = 92.7 lbm/hr/hp
100 psi, 550 hp, 34,000 lbm/hr — 34,000/550 = 61.8 lbm/hr/hp

INTERMEDIATE PRESSURE STEAM HEADER

Feedwater Heater

Design for full CHP capacity (4 boilers).

Feedwater	1,317 gpm	228°F ⇒ 302°F
Steam	75 psig	54,000 lbm
Temperature coefficient	6.5	

Material breakdown for feedwater piping:

Water Side		Steam Side	
Item	Qty.	Item	Qty
8" Pipe	112′	12" Pipe	16′
Elbows	10	Elbows	1
Tees	2	Tees	1
Valves	3	Valves	1

Turbines

Nozzles, Relief Valves, and Throttle Valve (Skinner Engine Co.)

Per turbine	$19,115
plus 10 hrs labor at $81.25	$813
Labor expenses	$2000

Steam Chest Piping

Increase from 4" to 6" diameter

		Total
Length	35′ per boiler	140′
Elbows	6 per boiler	24
12" tap	1 per boiler	4
Valves	2	8

EMC ENGINEERS, INC.
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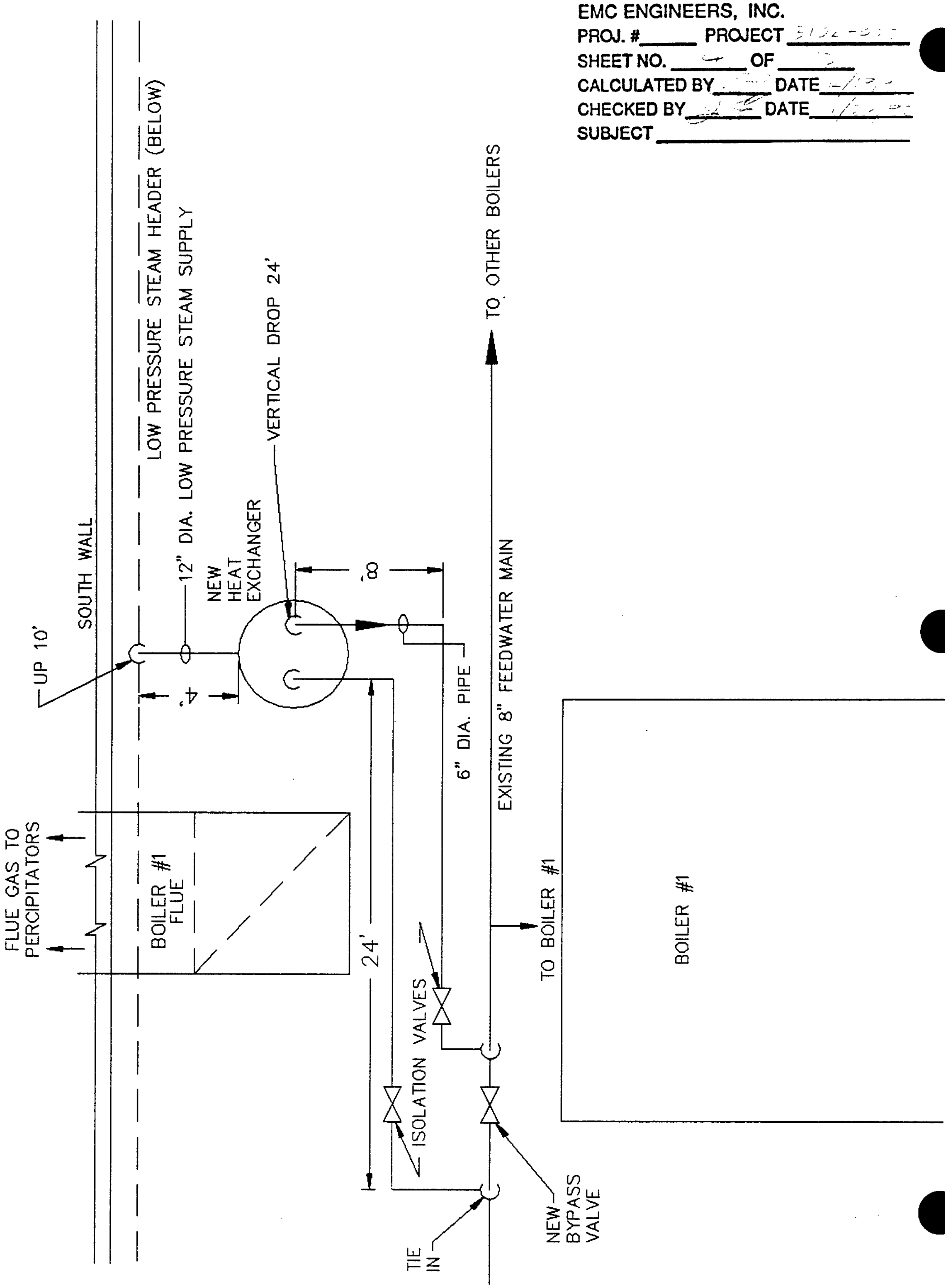

EMC ENGINEERS, INC.
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AREA-B COMPU[illegible]OILER MODEL - INTERMEDIATE PRESSURE STEAM HEADER ECO

BOILER75.WK3

HEATING VALUE OF COAL	HHV	14100.00	BTU/LBM	COAL ANALYSIS
THEORETICAL COMBUSTION AIR	THEO	11.00	LBM/LBM	LBH AIR/LBH COAL FROM ASHRAE FUNDAMENTALS
MIXED WATER TEMP	RETURN	56.00	F	LBH OF 5 PSI STEAM CONDENSED PER LBH OF MAKE UP
LATENT HEAT (5 PSI)	PSI5	960.00	BTU/LBM	STEAM TABLES
ECONOMOZER AIR TEMP IN	TEI	480	F	MEASURED
ECONOMIZER UA	ECON	25000.00	BTUH/F	AREA-A ECONOMIZER ANALYSIS
BLOWDOWN RATE	BLOW	2.46%	%	MEASURED
STEAM ENTHALPY	HS	1271.00	BTU/LBM	300 PSI, 525 F
LIQUID ENTHALPY	HL	399	BTU/LBM	300 PSI, SATURATED
LOW PRES STEAM ENTHALPY	HSLP	1,157	BTU/LBM	5 PSIG, SAT
DA HEATER LIQUID ENTHALPY	HLDA	196	BTU/LBM	228 F, SAT
AMBIENT TEMPERATURE	TA	56	F	WEATHER DATA
COMBUSTION LOSSES	LOSS	8.10%	%	ASSUMED
RADIATION LOSSES PER BOILER	RAD	1.65	MMBH	ASSUMED
DESIGN FAN HORSEPOWER	FANHP	550	HP	DESIGN DATA
DESIGN FAN CFM	FANCFM	52,500	CFM	DESIGN DATA
FAN STEAM RATE	FANSTM	45.50	LBH/HP	TURBINE MANUFACTURER
DA PUMP DESIGN HORSEPOWER	DAHP	80	HP	DESIGN DATA
DA PUMP DESIGN FLOW	DAGPM	1,750	GPM	DESIGN DATA
DA PUMP STEAM RATE	DASTM	54.8	LBH/HP	TURBINE MANUFACTURER
FW PUMP DESIGN HORSEPOWER	FWHP	135	HP	DESIGN DATA
FW PUMP DESIGN FLOW	FWGPM	460	GPM	DESIGN DATA
FW PUMP STEAM RATE	FWSTM	33.4	LBH/HP	TURBINE MANUFACTURER
BLOWDOWN FLASH STEAM	FLASH	21.10%	%	CALCULATED
FW PUMP HEAD	FWHEAD	700	FT	CALCULATED
VACUUM STEAM JET RATE	JET	932	LBH	CALCULATED
INTERMEDIATE HEADER PRESSU	IHP	75	PSIG	
INTERMEDIATE HEADER TEMP	IHT	320	F	
PRE-HEATER EFFECTIVENESS	IHE	0.80		
PRE-HEATER LATENT HEAT	IHH	895	BTU.LBM	
LOW PRESSURE STEAM TEMP	LPT	228	F	

							BLOWDOWN HEAT RECOVERY			DEAERATING HEATER				DA PUMPS			FEEDWATER PUMP	
CONDITION	NUMBER OF DAYS	CHP STEAM DEMAND (LBM/HR)	CHP STEAM BALANCE (LBM/HR)	BOILER STEAM FLOW (LBM/HR)	BOILERS ON LINE	TOTAL FEED WATER (LBM/HR)	BLOW DOWN LIQUID (LBM/HR)	HEAT EXCHANGE EFF	HEAT TRANSFER (BTUH)	LEAVING MAKE UP TEMP (F)	5 PSI STEAM (LBM/HR)	MAKE UP WATER (LBM/HR)	LEAVING MAKE UP TEMP (F)	DA PUMP FLOW (GPM)	DA PUMP POWER (HP)	DA PUMP STEAM (LBM/HR)	FW PUMP FLOW (GPM)	FW PUMP POWER (HP)
BASECASE	30	135,200	0	167,766	2	171,894	3,256	0.00	0	56	26,118	145,775	228	293	36	2,472	345	87
DESIGN	30		639,432	640,000	4	655,744	12,422	0.00	0	56	99,636	556,108	228	1,117	67	3,826	1,317	333
JAN	31	172,191	0	205,045	2	210,089	3,980	0.00	0	56	31,922	178,167	228	358	40	2,616	422	107
FEB	28	166,877	0	199,264	2	204,166	3,868	0.00	0	56	31,022	173,144	228	348	36	2,472	410	104
MAR	31	151,466	0	183,980	2	188,506	3,571	0.00	0	56	28,642	159,863	228	321	36	2,472	379	96
APR	30	139,980	0	172,540	2	176,785	3,349	0.00	0	56	26,861	149,923	228	301	36	2,472	355	90
MAY	31	123,623	0	156,170	2	160,012	3,031	0.00	0	56	24,313	135,699	228	272	36	2,472	321	81
JUN	30	117,555	0	149,900	2	153,587	2,909	0.00	0	56	23,337	130,251	228	262	32	2,301	308	78
JUL	31	116,885	0	149,226	2	152,897	2,896	0.00	0	56	23,232	129,665	228	260	32	2,301	307	78
AUG	31	116,907	0	149,248	2	152,919	2,897	0.00	0	56	23,236	129,684	228	260	32	2,301	307	78
SEP	30	119,133	0	151,659	2	155,390	2,944	0.00	0	56	23,610	131,779	228	265	36	2,472	312	79
OCT	31	132,672	0	165,239	2	169,303	3,207	0.00	0	56	25,726	143,579	228	288	36	2,472	340	86
NOV	30	151,630	0	184,143	2	188,673	3,574	0.00	0	56	28,668	160,005	228	321	36	2,472	379	96
DEC	31	166,331	0	198,724	2	203,612	3,857	0.00	0	56	30,938	172,675	228	347	36	2,472	409	103

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AREA-B COMPUTER BOILER MODEL - INTERMEDIATE PRESSURE STEAM HEADER ECO

BOILER75.WK3 DA PUMP CURVE

GPM	HEAD	EFF	HP	PLR	%HP
0	218	0%	0	0%	0%
100	218	16%	34	5%	34%
200	218	27%	41	10%	41%
300	217	36%	46	15%	45%
400	217	44%	50	20%	50%
600	215	55%	59	30%	59%
800	214	63%	69	40%	68%
1,000	211	70%	76	50%	76%
1,200	209	75%	84	60%	84%
1,400	202	80%	89	70%	89%
1,600	193	84%	93	80%	92%
1,800	184	86%	97	90%	97%
2,000	173	87%	100	100%	100%
2,400	145	85%	103	120%	103%
2,800	90	74%	86	140%	86%

	PART LOAD	STEAM OUT	BLOWDOWN	DRY FLUE L	FLUE HUMI	RADIATION	COMBUSTION LOSS
BASECASE		71.69%	0.71%	14.20%	3.89%	1.42%	8.10%
DESIGN		76.45%	0.75%	10.01%	3.89%	0.79%	8.10%

CONDITION	FW PUMP STEAM (LBM/HR)	STEAM PRE-HEATER: HEAT TRANSFER (BTUH)	STEAM DEMAND (LBM/HR)	LEAVING FW TEMP (F)	COMBUSTION AIR PREHEAER: HEAT EXCHANGE EFF	ENERGY EXCHANGE (BTUH)	PRE HEAT EXIT (F)	FLUE GAS EXIT (F)	BOILER INCLUDING ECONOMIZER: STEAM OUT (LBM/HR)	BOILER FEED WATER (LBM/HR)	ESTMTD OXYGEN	PERCENT EXCESS AIR	COMBUST AIR FLOW (LBM/HR)	STEAM OUT (MBH)	FDW IN (MBH)	STEAM PRODUCED (MBH)	BLOW DOWN LOSS (MBH)	DRY FLUE LOSS (MBH)
BASECASE	3,231	12,702,174	14,192	302	0.00	0	56	411	83,883	85,947	10.40%	98%	179,995	107	23	83	1	17
DESIGN	9,787	48,456,585	54,141	302	0.00	0	56	419	160,000	163,936	5.33%	34%	217,635	203	44	159	2	21
JAN	3,748	15,524,627	17,346	302	0.00	0	56	414	102,522	105,044	9.16%	77%	192,730	130	28	102	1	18
FEB	3,668	15,086,974	16,857	302	0.00	0	56	413	99,632	102,083	9.35%	80%	190,966	127	28	99	1	18
MAR	3,456	13,929,736	15,564	302	0.00	0	56	412	91,990	94,253	9.86%	89%	185,950	117	25	92	1	17
APR	3,297	13,063,610	14,596	302	0.00	0	56	411	86,270	88,392	10.25%	95%	181,822	110	24	86	1	17
MAY	3,070	11,824,187	13,211	302	0.00	0	56	410	78,085	80,006	10.79%	106%	175,267	99	22	78	1	16
JUN	2,983	11,349,435	12,681	302	0.00	0	56	409	74,950	76,794	11.00%	110%	172,626	95	21	75	1	16
JUL	2,973	11,298,378	12,624	302	0.00	0	56	409	74,613	76,448	11.02%	110%	172,223	95	21	74	1	16
AUG	2,974	11,300,055	12,626	302	0.00	0	56	409	74,624	76,460	11.02%	110%	172,233	95	21	74	1	16
SEP	3,007	11,482,624	12,830	302	0.00	0	56	409	75,830	77,695	10.94%	109%	173,309	96	21	75	1	16
OCT	3,196	12,510,773	13,979	302	0.00	0	56	411	82,619	84,652	10.49%	100%	179,000	105	23	82	1	16
NOV	3,458	13,942,079	15,578	302	0.00	0	56	412	92,071	94,336	9.86%	88%	186,006	117	25	92	1	17
DEC	3,661	15,046,063	16,811	302	0.00	0	56	413	99,362	101,806	9.37%	81%	190,797	126	27	99	1	18

AREA-B COMPU[illegible]BOILER MODEL - INTERMEDIATE PRESSURE STEAM HEADER ECO

BOILER75.WK3	DA PUMP	FW PUMP	DRAFT FAN	MISCELLAN	STEAM TO LOAD
	2,472	3,231	39,264	1,803	136,200

EMC ENGINEERS, INC.
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								ECONOMIZER					DRAFT FANS				CENTRAL HEATING PLA	
CONDITION	FUEL HUMIDITY LOSS (MBH)	RADIATION LOSS (MBH)	COMBUST LOSSES (MBH)	FUEL IN (MBH)	COAL FLOW (LBM/HR)	FLUE GAS FLOW (LBM/HR)	BOILER EFF	CAPACITY RATIO	NTU	EFF	EXIT AIR (F)	EXIT WATER (F)	FORCED DRAFT (SCFM)	INDUCED DRAFT (SCFM)	TOTAL HP	FAN STEAM (LBM/HR)	BLOW DOWN FLASH (LBM/HR)	TOTAL LO PRES STEAM (LBM/HR)
BASECASE	5	2	9	116	8,266	187,837	71.7%	0.62	0.55	0.39	411	339	39,999	41,742	402	19,627	871	31,634
DESIGN	8	2	17	208	14,765	231,662	76.6%	0.34	0.45	0.34	419	323	48,363	61,480	497	23,083	3,322	66,126
JAN	5	2	11	139	9,877	202,113	73.2%	0.46	0.62	0.37	414	333	42,829	44,914	432	20,726	1,064	31,536
FEB	5	2	11	136	9,627	200,112	73.0%	0.47	0.62	0.37	413	334	42,437	44,469	428	20,569	1,034	31,455
MAR	5	2	10	126	8,964	194,465	72.4%	0.50	0.64	0.38	412	336	41,322	43,216	416	20,132	955	31,582
APR	5	2	10	119	8,465	189,864	71.9%	0.52	0.65	0.39	411	338	40,405	42,192	406	19,780	896	31,628
MAY	4	2	9	109	7,745	182,625	71.1%	0.55	0.67	0.39	410	341	38,948	40,683	391	19,237	811	31,615
JUN	4	2	9	105	7,468	179,621	70.8%	0.56	0.68	0.40	409	343	38,339	39,916	386	19,016	778	31,413
JUL	4	2	8	105	7,438	179,290	70.8%	0.56	0.68	0.40	409	343	38,272	39,842	384	18,992	775	31,409
AUG	4	2	8	105	7,439	179,301	70.8%	0.56	0.68	0.40	409	343	38,274	39,846	384	18,993	775	31,409
SEP	4	2	9	106	7,546	180,478	70.9%	0.56	0.68	0.40	409	342	38,513	40,106	387	19,079	787	31,594
OCT	4	2	9	115	8,145	186,737	71.6%	0.53	0.56	0.39	411	340	39,778	41,497	399	19,644	858	31,636
NOV	5	2	10	126	8,971	194,528	72.4%	0.49	0.54	0.38	412	336	41,335	43,229	416	20,137	956	31,581
DEC	5	2	11	135	9,604	199,921	73.0%	0.47	0.52	0.37	413	334	42,399	44,427	427	20,554	1,031	31,461

EMC ENGINEERS, INC.
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AREA-B COMPUTER BOILER MODEL - INTERMEDIATE PRESSURE STEAM HEADER ECO

BOILER75.WK3

NT

CONDITION	EXCESS LO PRES STEAM (LBM/HR)	EXCESS LO PRES VENT (LBM/HR)	PRV STEAM (LBM/HR)	TOTAL IN PLANT STEAM (LBM/HR)	TOTAL IN PLANT STEAM	STEAM TO LOAD (LBM/HR)	FUEL IN (MBH)	MONTHLY FUEL IN (MBH)	STEAM TO LOAD (MBH)	MAKE UP WATER (MBH)	CHP ENERGY ADDED (MBH)	CHP EFF	STEAM JET (MBH)	FLUE LOSS (MBH)	COMBUSTI LOSS (MBH)	EXCESS STEAM VENT (MBH)
BASECASE	5,516	5,516	0	32,566	19.41%	135,200	232.8	167,622	172	3	168	72.3%	1	42	19	6.382
DESIGN	(44,511)	0	44,511	100,568	15.71%	539,432	832.8	699,588	686	13	672	80.7%	1	116	67	0.000
JAN	(387)	0	387	32,854	16.02%	172,191	278.5	207,227	219	4	215	77.0%	1	47	23	0.000
FEB	434	434	0	32,387	16.25%	166,877	271.5	182,439	212	4	208	76.6%	1	46	22	0.502
MAR	2,940	2,940	0	32,514	17.67%	151,466	252.8	188,072	193	4	189	74.6%	1	44	20	3.401
APR	4,767	4,767	0	32,560	18.87%	139,980	238.7	171,868	178	4	174	73.0%	1	43	19	5.516
MAY	7,303	7,303	0	32,547	20.84%	123,623	218.4	162,504	157	3	164	70.4%	1	41	18	8.449
JUN	8,076	8,076	0	32,345	21.58%	117,555	210.6	151,631	149	3	146	69.5%	1	40	17	9.344
JUL	8,177	8,177	0	32,341	21.67%	116,885	209.8	156,069	149	3	145	69.3%	1	40	17	9.461
AUG	8,174	8,174	0	32,341	21.67%	116,907	209.8	156,079	149	3	145	69.3%	1	40	17	9.457
SEP	7,984	7,984	0	32,526	21.45%	119,133	212.8	153,213	151	3	148	69.7%	1	40	17	9.237
OCT	5,910	5,910	0	32,567	19.71%	132,672	229.7	170,881	169	3	165	71.9%	1	42	19	6.838
NOV	2,913	2,913	0	32,513	17.66%	161,630	253.0	182,149	193	4	189	74.7%	1	44	20	3.371
DEC	523	523	0	32,393	16.30%	166,331	270.8	201,496	211	4	207	76.5%	1	46	22	0.605
								2,083,619								

McCOY
SALES CORPORATION

EMC ENGINEERS, INC.
PROJ. #______ PROJECT ______
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QUOTATION

To EMC Engineers

Attn Dennis Jones

Phone 988-2951, FAX: 985-2527

Job

Date 01/30/92

Terms 1% 10th Net-30

F.O.B. Englewood, CO

Delivery 8 to 10 weeks

QTY	DESCRIPTION	SELL EACH	WEIGHT
1	Taco G30420-S Heat Exchanger	$53,270.00	4800#

Bill Trebing

BILL Trebing

MANUFACTURERS' REPRESENTATIVE
2190 W. BATES AVE. • ENGLEWOOD, CO 80110 • (303) 762-8012

EMC ENGINEERS, INC.
PROJ. # ______ PROJECT ______
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Wednesday, January 29, 1992

Taco, Inc.
TACO HEAT EXCHANGER SELECTION, Version 3.00

** INPUT PARAMETERS **

Tubeside		Shellside	
Fluid Type: Water		Fluid Type: Steam	
Flow Rate (gpm):	1320.00	Steam Press.(psig):	75.00
Entering Temp. (°F):	228.0		
Leaving Temp. (°F):	295.0		
Fouling:	0.0005		
Load (MBh):	43569.92		

Tube Material: Copper .035 Wall
Maximum Length (ft): 10.0
LMTD: 51.4
Sat. Stm. Temp. (°F): 320.0

** SELECTION RESULTS **

Model Num.	Dia. (in)	Num. Passes	Length (ft)	Baff. Pitch	Tube Vel.(fps)	Tube Pd.(ft)	Shell Vel.(fps)	Shell Pd.(ft)
G30420- S	30	4	10		6.44	14.71		

Submittal Data Information
U Tube Heat Exchangers

TACO

201-019

30" DIAMETER STEAM **SUPERSEDES: SD200B**

Job: EMC Engineers

Item No.	Model No.	Pass	GPM Tubes	Temp. In	Temp. Out	Steam Pressure Shell	Pressure Drop Tubes	Velocity Tubes
	G30420-S	4	1320	228°F	295°F	75	14.71'HD	6.44FPS

EMC EN ERS, INC.
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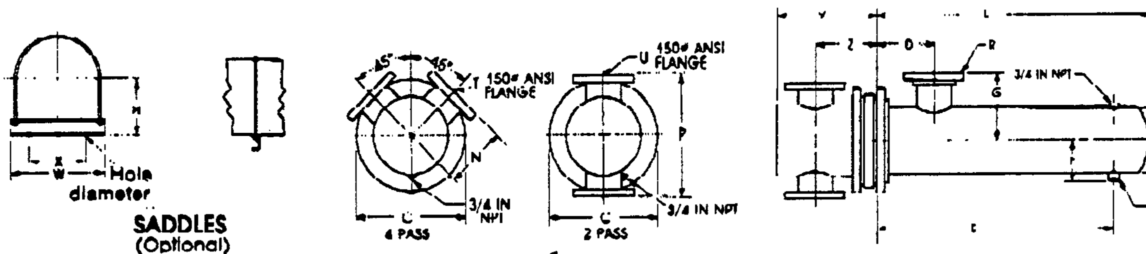


SADDLES
(Optional)

DIMENSIONS
30 Inch Diameter

Model Number		Fabricated Steel Heads								Dimensions (Inches)									Heating Surface (sq.ft.)	Shipping Weight (lbs.)
2 Pass	4 Pass	2 Pass P	U	V	Z	4 Pass N	T	V	Z	2 and 4 Pass A	C	D	E	F	G	L	R	S		
G30206S	G30406S	42	14F	31⅞	21⅛	20¾	10F	28⅞	19¾	30	38¾	16	23	20	22	38½	16F	6F	377.6	2567
G30208S	G30408S	42	14F	31⅞	21⅛	20¾	10F	28⅞	19¾	30	38¾	16	35	20	22	50½	16F	6F	520.5	2886
G30210S	G30410S	42	14F	31⅞	21⅛	20¾	10F	28⅞	19¾	30	38¾	16	47	20	22	62½	16F	6F	663.4	3205
G30212S	G30412S	42	14F	31⅞	21⅛	20¾	10F	28⅞	19¾	30	38¾	16	59	20	22	74½	16F	6F	806.3	3524
G30214S	G30414S	42	14F	31⅞	21⅛	20¾	10F	28⅞	19¾	30	38¾	16	71	20	22	86½	16F	6F	949.2	3843
G30216S	G30416S	42	14F	31⅞	21⅛	20¾	10F	28⅞	19¾	30	38¾	16	83	20	22	98½	16F	6F	1092	4162
G30218S	G30418S	42	14F	31⅞	21⅛	20¾	10F	28⅞	19¾	30	38¾	17	95	20	22	110½	18F	8F	1235	4481
G302[illegible]	G30420S	42	14F	31⅞	21⅛	20¾	10F	28⅞	19¾	30	38¾	17	107	20	22	122½	18F	8F	1378	4800

SADDLE DIMENSIONS: H-21: W-33: X-22: Hole Dia.-⅞.

MATERIALS OF CONSTRUCTION (Unless otherwise indicated, standard will be furnished.)

	Standard	Optional
Shell	Steel	304ss, 316ss
Head	Cast Iron 4-10" Fabricated Steel 12-30"	Fabricated Steel, Cast Bronze, Fabricated 304ss/316ss Cast Bronze, Fabricated 304ss/316ss
Tubes	3/4 x 20 BWG Copper	3/4 x 18 BWG Copper, Steel, 304ss, 316ss, 90/10 Cu Ni, Admiralty
Tube Sheet	Steel	Bronze, Brass, 304ss, 316ss, 90/10 Cu Ni
Separators	Steel	Bronze, Brass, 304ss, 316ss, 90/10 Cu Ni
Working Pressure	150 PSIG (ASME)	Consult Factory
Max. Temperature	375°F	Consult Factory

Quality Through Design — COMPARE.

TACO, Inc., 1160 Cranston St., Cranston, RI 02920 (401) 942-8000 Telex: 92-7627
TACO, (Canada) Ltd., 1310 Aimco Blvd., Mississauga, Ontario L4W 1B2 (416) 625-2160 Telex: 06 961179

Form No. F201-019 Effective 10/1/84

ENGINEERS OPINION OF PROBABLE COST

Project	**Holston Army Ammunition Plant** **Limited Energy Studies – DACA01-91-D-0032**	**SHEET 12 OF 13**
		DATE PREPARED **07/16/92**
Engineer	**EMC Engineers, Inc – PN# 3102-002** **Denver, CO**	**Estimator D JONES**
Description	**INTERMEDIATE STEAM PRESSURE HEADER**	**Checked by**

Description	Quantity		Material		Labor			Total Cost
	No. Units	Unit Meas.	Per Unit	Total	Hours Per Unit	Hourly Rate	Total	
RENOZZLE TURBINES								
(NOZZLES, RELIEF VALVE,								
CONTROL VALVE)	4	EA	$19,115.00	$76,460	10	$81.25	$3,250	$79,710
FACTORY LABOR EXPENSES	1	LS	$2,000.00	$2,000				$2,000
FEEDWATER HEATER	1	EA	$53,270.00	$53,270	20	$16.89	$338	$53,608
FEEDWATER STEAM PIPING								
12 IN STEEL PIPE, SCH 80, WLD								
PIPE	16	FT	59.14	$946	1.6	$16.89	$432	$1,379
ELBOWS	2	EA	215	$430	10.67	$16.89	$360	$790
TEE 14X12	1	EA	275	$275	16	$16.89	$270	$545
GATE VALVE	1	EA	6575	$6,575	15	$16.89	$253	$6,828
FAN TURBINE PIPING								
6 IN STEEL PIPE, SCH 80, WLD								
PIPE	140	FT	$25.10	$3,514	0.8	$16.89	$1,892	$5,406
ELBOWS	24	EA	$45.00	$1,080	5.33	$16.89	$2,161	$3,241
TEE 14X6	4	EA	$245.00	$980	9.6	$16.89	$649	$1,629
GATE VALVE	8	EA	$2,025.00	$16,200	8.3	$16.89	$1,121	$17,321
FEEDWATER HEATER PIPING								
8 IN STEEL PIPE, SCH 80, WLD								
PIPE	120	FT	$37.67	$4,520	0.96	$16.89	$1,946	$6,466
ELBOWS	10	EA	$86.00	$860	6.86	$16.89	$1,159	$2,019
TEE	2	EA	$115.00	$230	12	$16.89	$405	$635
GATE VALVE	3	EA	$3,050.00	$9,150	10	$16.89	$507	$9,657
PIPE INSULN, 500 DEG FIBERGLS								
6 IN, 2 IN THK WITH ASJ	140	FT	$6.45	$903	0.16	$16.89	$378	$1,281
8 IN, 2 IN THK WITH ASJ	120	FT	$7.96	$955	0.2	$16.89	$405	$1,361
12 IN, 2 IN THK WITH ASJ	14	FT	$10.50	$147	0.246	$16.89	$58	$205
DEMOLITION	140	FT			0.053	$16.89	$125	$125
PRESSURE REDUCING STATION	1	EA	8900	$8,900	11	$16.89	$186	$9,086
CONDENSATE PIPING								
1 IN STEEL PIPE, SCH 80, WLD								
PIPE	200	FT	1.68	$336	0.188	$16.89	$635	$971
ELBOWS	12	EA	4	$48	1	$16.89	$203	$251
TEE	1	EA	11.35	$11	1.6	$16.89	$27	$38
GATE VALVE	3	EA	115	$345	1	$16.89	$51	$396
PIPE INSULN, 500 DEG FIBERGLS								
6 IN, 2 IN THK WITH ASJ	200	FT	3.59	$718	0.08	$16.89	$270	$988
STEAM TRAP, 1"	1	EA	194	$194	1	$16.89	$17	$211
SUBTOTAL				$189,048			$17,099	$206,147
OVERHEAD & BOND	0.16			$30,248			$2,736	$32,983
SUBTOTAL				$219,296			$19,834	$239,130
PROFIT	0.1			$21,930			$1,983	$23,913
SUBTOTAL				$241,225			$21,818	$263,043
CONTINGENCY	0.2			$48,245			$4,364	$52,609
TOTAL ESTIMATED COST				$289,471			$26,181	$315,652

LIFE CYCLE COST ANALYSIS SUMMARY
ENERGY CONSERVATION INVESTMENT PROGRAM (ECIP)

LOCATION:	HOLSTON AAP	REGION:	4
PROJ. NO. & TITLE:	DACA01-91-D-0032 LIMITED ENERGY STUDIES		
DISCRETE PORTION:	INTERMEDIATE PRESSURE STEAM HEADER		
FISCAL YEAR:	91	ECONOMIC LIFE	25
ANALYSIS DATE:	16-Jul-92	PREPARED BY: D JONES	

1 INVESTMENT

A.	CONSTRUCTION COST		=	$315,652
B.	SIOH COST	(5.5% of 1A)	=	$17,361
C.	DESIGN COST	(6.0% of 1A)	=	$18,939
D.	SALVAGE VALUE		=	$0
E.	TOTAL INVESTMENT	(1A + 1B +1C +1D – 1E)	=	$351,952

2 ENERGY SAVINGS (+) / COST (–)

	FUEL TYPE	FUEL COST $/MBTU (1)	SAVINGS MBTU/YR (2)	ANNUAL $ SAVINGS (3)	DISCOUNT FACTOR (4)	DISCOUNTED SAVINGS (5)
A.	ELEC	$4.67	0	$0	15.61	$0
B.	DIST		0	$0	0.00	$0
C.	RESID		0	$0	0.00	$0
D.	NAT GAS		0	$0		$0
E.	COAL	$1.25	72,484	$90,605	16.06	$1,455,116
F.	TOTAL ENERGY SAVINGS		72,484	$90,605		$1,455,116

3 NON-ENERGY SAVINGS (+) / COST (–)

A. ANNUAL RECURRING

	ANNUAL $	DISCOUNT FACTOR	DISCOUNTED SAVINGS
ADDED MAINTENANCE COST	($400)	14.53	($5,812)
ELECTRIC DEMAND SAVINGS 0 KW * $9.50/KW/MTH * 12 MTHS =	$0	14.53	$0
TOTAL SAVINGS (+) / COST (–)	($400)		($5,812)

B. NON-RECURRING (+/–)

ITEM	YEAR OF OCCURRENCE			
a.		$0	0.00	$0
b.		$0	0.00	$0
c.		$0	0.00	$0
TOTAL SAVINGS (+) / COST (–)		$0		$0

C. TOTAL NON ENERGY DISCOUNTED SAVINGS (3A + 3B) ($5,812)

D. PROJECT NON-ENERGY QUALIFICATION TEST
NON ENERGY SAVINGS % (3C / (3C + 2F)) -0%

4 FIRST YEAR DOLLAR SAVINGS (+) / COSTS (–)	$90,205	
5 TOTAL NET DISCOUNTED SAVINGS		$1,449,304
6 DISCOUNTED SAVINGS-TO-INVESTMENT RATIO (SIR)		4.12
7 SIMPLE PAYBACK (YEARS)		3.90

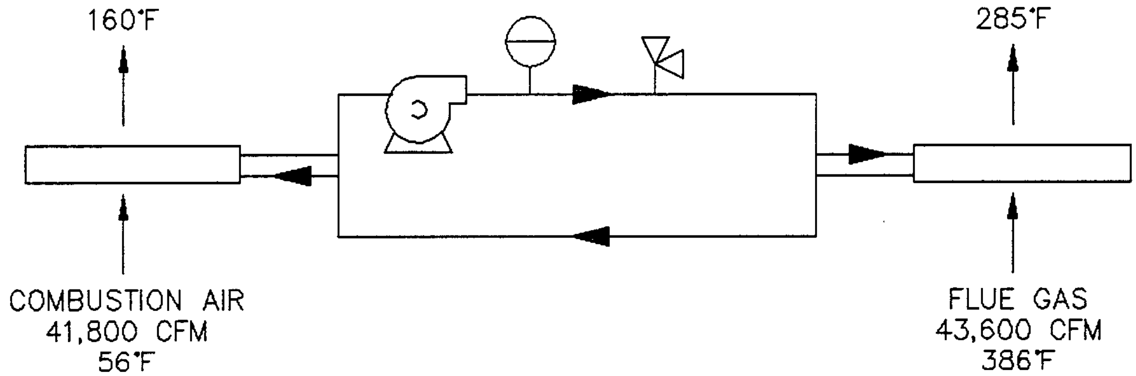
EMC ENGINEERS, INC.
PROJ. #____ PROJECT 3/2?-002
SHEET NO. 13 OF 17
CALCULATED BY DS DATE 7/..92
CHECKED BY____ DATE____
SUBJECT____

APPENDIX F

AREA-B AIR PREHEATER ANALYSIS

PROPOSED MODIFICATION

AREA B AIR PREHEATER



ENERGY SAVINGS (FROM BOILER MODEL)

BASE CASE	2,155,572 MBTU – ANNUAL COAL USAGE
AIR PREHEATER	2,032,323 MBTU
SAVINGS	$\boxed{123,249 \text{ MBTU/YR}}$

MAINTENANCE COSTS

40 HRS/YR @ $25 = $\boxed{\$1,000/\text{YR}}$

ELECTRIC ENERGY USAGE

$$\frac{100 \text{ GPM}}{3960} \times \frac{10' \text{ WC}}{0.7} = 0.36 \text{ HP}$$

$$\frac{0.36 \text{ HP}}{0.85} \times \frac{0.746 \text{ kW}}{\text{HP}} = \boxed{0.317 \text{ kW}}$$

ANNUAL ELECTRICITY USE = 8,760 x 0.317 = $\boxed{2,774 \text{ kWH}}$
= $\boxed{9.5 \text{ MMBTU}}$

EMC ENGINEERS, INC.
PROJ. # ____ PROJECT 312-002
SHEET NO. 1 OF 11
CALCULATED BY BG DATE 1/14/92
CHECKED BY JE DATE 1/21/92
SUBJECT ____

EMC ENGINEERS, INC.
PROJ. #______ PROJECT 3102-012
SHEET NO. 2 OF 11
CALCULATED BY ____ DATE 1/2?/92
CHECKED BY ________ DATE __________
SUBJECT ____________________

AREA-B COMPUTER BOILER MODEL - AIR PREHEATER ECO

BOILBAIR.WK3

HEATING VALUE OF COAL	HHV	14100.00	BTU/LBM	COAL ANALYSIS
THEORETICAL COMBUSTION AIR	THEO	11.00	LBM/LBM	LBH AIR/LBH COAL FROM ASHRAE FUNDAMENTALS
MIXED WATER TEMP	RETURN	56.00	F	LBH OF 5 PSI STEAM CONDENSED PER LBH OF MAKE UP
LATENT HEAT (5 PSI)	PSI5	960.00	BTU/LBM	STEAM TABLES
ECONOMOZER AIR TEMP IN	TEI	480	F	MEASURED
ECONOMIZER UA	ECON	25000.00	BTUH/F	AREA-A ECONOMIZER ANALYSIS
BLOWDOWN RATE	BLOW	2.46%	%	MEASURED
STEAM ENTHALPY	HS	1271.00	BTU/LBM	300 PSI, 525 F
LIQUID ENTHALPY	HL	399	BTU/LBM	300 PSI, SATURATED
LOW PRES STEAM ENTHALPY	HSLP	1,157	BTU/LBM	5 PSIG, SAT
DA HEATER LIQUID ENTHALPY	HLDA	196	BTU/LBM	228 F, SAT
AMBIENT TEMPERATURE	TA	56	F	WEATHER DATA
COMBUSTION LOSSES	LOSS	8.10%	%	ASSUMED
RADIATION LOSSES PER BOILER	RAD	1.65	MMBH	ASSUMED
DESIGN FAN HORSEPOWER	FANHP	550	HP	DESIGN DATA
DESIGN FAN CFM	FANCFM	62,500	CFM	DESIGN DATA
FAN STEAM RATE	FANSTM	21.60	LBH/HP	TURBINE MANUFACTURER
DA PUMP DESIGN HORSEPOWER	DAHP	80	HP	DESIGN DATA
DA PUMP DESIGN FLOW	DAGPM	1,750	GPM	DESIGN DATA
DA PUMP STEAM RATE	DASTM	54.8	LBH/HP	TURBINE MANUFACTURER
FW PUMP DESIGN HORSEPOWER	FWHP	135	HP	DESIGN DATA
FW PUMP DESIGN FLOW	FWGPM	460	GPM	DESIGN DATA
FW PUMP STEAM RATE	FWSTM	33.4	LBH/HP	TURBINE MANUFACTURER
BLOWDOWN FLASH STEAM	FLASH	21.10%	%	CALCULATED
FW PUMP HEAD	FWHEAD	700	FT	CALCULATED
VACUUM STEAM JET RATE	JET	932	LBH	CALCULATED
INTERMEDIATE HEADER PRESSU	IHP	5	PSIG	
INTERMEDIATE HEADER TEMP	IHT	228	F	
PRE-HEATER EFFECTIVENESS	IHE	0.80		
PRE-HEATER LATENT HEAT	IHH	960	BTU.LBM	
LOW PRESSURE STEAM TEMP	LPT	228	F	

							BLOWDOWN HEAT RECOVERY				DEAERATING HEATER			DA PUMPS			FEEDWATER PUMP	
CONDITION	NUMBER OF DAYS	CHP STEAM DEMAND (LBM/HR)	CHP STEAM BALANCE (LBM/HR)	BOILER STEAM FLOW (LBM/HR)	BOILERS ON LINE	TOTAL FEED WATER (LBM/HR)	BLOW DOWN LIQUID (LBM/HR)	HEAT EXCHANGE EFF	HEAT TRANSFER (BTUH)	LEAVING MAKE UP TEMP (F)	5 PSI STEAM (LBM/HR)	MAKE UP WATER (LBM/HR)	LEAVING MAKE UP TEMP (F)	DA PUMP FLOW (GPM)	DA PUMP POWER (HP)	DA PUMP STEAM (LBM/HR)	FW PUMP FLOW (GPM)	FW PUMP POWER (HP)
BASECASE	30	135,200	(0)	161,891	2	165,873	3,142	0.00	0	56	25,203	140,670	228	282	36	2,472	333	84
DESIGN	30		639,432	640,000	4	665,744	12,422	0.00	0	56	99,636	566,108	228	1,117	67	3,826	1,317	333
AIR PREHEATER	30	135,200	0	161,233	2	165,199	3,129	0.00	0	56	25,101	140,098	228	281	36	2,472	332	84
JAN	31	172,191	0	205,045	2	210,089	3,980	0.00	0	56	31,922	178,167	228	358	40	2,616	422	107
FEB	28	166,877	0	198,751	2	203,640	3,858	0.00	0	56	30,942	172,698	228	347	36	2,472	409	103
MAR	31	151,466	0	180,498	2	184,938	3,503	0.00	0	56	28,100	156,838	228	315	36	2,472	371	94
APR	30	139,980	0	166,894	2	171,000	3,239	0.00	0	56	25,982	145,018	228	291	36	2,472	343	87
MAY	31	123,623	0	148,651	2	152,206	2,883	0.00	0	56	23,127	129,079	228	259	32	2,301	306	77
JUN	30	117,555	(0)	142,113	2	145,609	2,758	0.00	0	56	22,124	123,485	228	248	32	2,301	292	74
JUL	31	116,885	0	141,402	2	144,880	2,745	0.00	0	56	22,014	122,867	228	247	32	2,301	291	73
AUG	31	116,907	0	141,425	2	144,904	2,745	0.00	0	56	22,017	122,887	228	247	32	2,301	291	73
SEP	30	119,133	0	143,788	2	147,325	2,791	0.00	0	56	22,386	124,940	228	251	32	2,301	296	75
OCT	31	132,672	0	158,319	2	162,213	3,073	0.00	0	56	24,647	137,566	228	276	36	2,472	326	82
NOV	30	151,630	0	180,692	2	185,137	3,507	0.00	0	56	28,130	167,007	228	316	36	2,472	372	94
DEC	31	166,331	0	198,104	2	202,977	3,845	0.00	0	56	30,841	172,136	228	346	36	2,472	408	103

AREA-B COMP[illegible] BOILER MODEL - AIR PREHEATER ECO

BOILBAIR.WK3 DA PUMP CURVE

GPM	HEAD	EFF	HP	PLR	%HP
0	218	0%	0	0%	0%
100	218	16%	34	5%	34%
200	218	27%	41	10%	41%
300	217	36%	46	15%	45%
400	217	44%	50	20%	50%
600	215	55%	59	30%	59%
800	214	63%	69	40%	68%
1,000	211	70%	76	50%	76%
1,200	209	75%	84	60%	84%
1,400	202	80%	89	70%	89%
1,600	193	84%	93	80%	92%
1,800	184	86%	97	90%	97%
2,000	173	87%	100	100%	100%
2,400	145	85%	103	120%	103%
2,800	90	74%	86	140%	86%

PART LOAD	STEAM OUT	BLOWDOWN	DRY FLUE L	FLUE HUMI	RADIATION	COMBUSTION LOSS
BASECASE	72.62%	0.67%	13.44%	3.89%	1.38%	8.10%
DESIGN	77.12%	0.71%	9.43%	3.89%	0.74%	8.10%

EMC ENGINEERS, INC.
PROJ. #______ PROJECT 3102-002
SHEET NO. 3 OF 11
CALCULATED BY [illegible] DATE 1/29/92
CHECKED BY ______ DATE ______
SUBJECT ______

		STEAM PRE-HEATER			COMBUSTION AIR PREHEAER				BOILER INCLUDING ECONOMIZER									
CONDITION	FW PUMP STEAM (LBM/HR)	HEAT TRANSFER (BTUH)	STEAM DEMAND (LBM/HR)	LEAVING FW TEMP (F)	HEAT EXCHANGE EFF	ENERGY EXCHANGE (BTUH)	PRE HEAT EXIT (F)	FLUE GAS EXIT (F)	STEAM OUT (LBM/HR)	BOILER FEED WATER (LBM/HR)	ESTMTD OXYGEN	PERCENT EXCESS AIR	COMBUST AIR FLOW (LBM/HR)	STEAM OUT (MBH)	FDW IN (MBH)	STEAM PRODUCED (MBH)	BLOW DOWN LOSS (MBH)	DRY FLUE LOSS (MBH)
BASECASE	3,149	(0)	(0)	228	0.00	0	56	386	80,945	82,937	10.60%	102%	188,181	103	16	87	1	16
DESIGN	9,787	0	0	228	0.00	0	56	398	160,000	163,936	6.33%	34%	232,093	203	32	171	2	21
AIR PREHEATER	3,140	0	0	228	0.32	4,431,026	160	285	80,616	82,600	10.62%	102%	177,347	102	16	86	1	10
JAN	3,748	0	0	228	0.32	4,944,523	162	289	102,522	105,044	9.16%	77%	194,612	130	21	110	1	11
FEB	3,661	0	0	228	0.32	4,879,110	162	289	99,375	101,820	9.37%	81%	192,428	126	20	106	1	11
MAR	3,408	0	0	228	0.32	4,674,623	161	287	90,249	92,469	9.98%	91%	185,569	115	18	97	1	11
APR	3,219	(0)	(0)	228	0.32	4,506,826	160	285	83,447	85,500	10.43%	99%	179,879	106	17	89	1	10
MAY	2,964	0	0	228	0.32	4,262,690	159	283	74,276	76,103	11.05%	111%	171,281	94	15	79	1	10
JUN	2,875	0	0	228	0.32	4,155,734	159	282	71,057	72,804	11.26%	116%	167,973	90	14	76	1	9
JUL	2,865	0	0	228	0.32	4,144,756	159	282	70,701	72,440	11.28%	116%	167,698	90	14	76	1	9
AUG	2,865	0	0	228	0.32	4,145,117	159	282	70,712	72,452	11.28%	116%	167,610	90	14	76	1	9
SEP	2,898	0	0	228	0.32	4,181,364	159	282	71,894	73,663	11.20%	114%	168,850	91	14	77	1	10
OCT	3,100	0	0	228	0.32	4,391,393	160	284	79,159	81,107	10.72%	104%	176,003	101	16	86	1	10
NOV	3,410	0	0	228	0.32	4,676,826	161	287	90,346	92,569	9.97%	90%	185,646	115	18	97	1	11
DEC	3,652	0	0	228	0.32	4,872,248	162	289	99,052	101,489	9.39%	81%	192,199	126	20	106	1	11

EMC ENGINEERS, INC.
PROJ. #_____ PROJECT 2161-007
SHEET NO. 4 OF 11
CALCULATED BY _____ DATE 1/29/92
CHECKED BY _____ DATE _____
SUBJECT _____

AREA-B COMPUTER BOILER MODEL - AIR PREHEATER ECO

BOILBAIR.WK3	DA PUMP	FW PUMP	DRAFT FAN	MISCELLAN	STEAM TO LOAD
	2,472	3,149	19,298	1,772	136,200

								ECONOMIZER					DRAFT FANS				CENTRAL HEATING PLA	
CONDITION	FUEL HUMIDITY LOSS (MBH)	RADIATION LOSS (MBH)	COMBUST LOSSES (MBH)	FUEL IN (MBH)	COAL FLOW (LBM/HR)	FLUE GAS FLOW (LBM/HR)	BOILER EFF	CAPACITY RATIO	NTU	EFF	EXIT AIR (F)	EXIT WATER (F)	FORCED DRAFT (SCFM)	INDUCED DRAFT (SCFM)	TOTAL HP	FAN STEAM (LBM/HR)	BLOW DOWN FLASH (LBM/HR)	TOTAL LO PRES STEAM (LBM/HR)
BASECASE	5	2	10	119	8,471	196,229	72.6%	0.57	0.63	0.37	386	283	41,818	43,606	421	9,649	840	25,759
DESIGN	9	2	18	222	15,746	247,052	77.1%	0.36	0.42	0.33	398	259	51,576	54,900	538	11,668	3,322	63,605
AIR PREHEATER	4	2	9	112	7,967	184,916	76.8%	0.54	0.56	0.39	381	283	39,410	41,092	396	9,213	837	24,875
JAN	5	2	11	141	9,973	204,087	78.0%	0.47	0.51	0.37	387	273	43,247	45,353	437	9,919	1,064	27,267
FEB	5	2	11	137	9,687	201,630	77.9%	0.48	0.52	0.37	386	274	42,762	44,807	431	9,826	1,032	26,817
MAR	5	2	10	126	8,852	193,979	77.4%	0.50	0.54	0.38	384	278	41,238	43,106	415	9,541	937	25,899
APR	5	2	9	116	8,228	187,696	77.0%	0.53	0.55	0.39	382	281	39,973	41,710	401	9,313	866	25,182
MAY	4	2	8	104	7,381	178,293	76.4%	0.56	0.58	0.40	379	287	38,062	39,621	382	8,980	771	23,996
JUN	4	2	8	100	7,082	174,701	76.2%	0.58	0.60	0.40	378	289	37,327	38,823	375	8,856	738	23,626
JUL	4	2	8	99	7,049	174,294	76.1%	0.58	0.60	0.40	378	289	37,244	38,732	374	8,842	734	23,585
AUG	4	2	8	99	7,050	174,308	76.1%	0.58	0.60	0.40	378	289	37,247	38,735	374	8,843	734	23,586
SEP	4	2	8	101	7,160	175,652	76.2%	0.57	0.69	0.40	378	288	37,522	39,034	377	8,889	746	23,723
OCT	4	2	9	110	7,832	183,444	76.7%	0.54	0.57	0.39	381	284	39,112	40,765	393	9,161	822	24,715
NOV	5	2	10	125	8,861	194,064	77.4%	0.50	0.54	0.38	384	278	41,255	43,125	416	9,545	938	25,909
DEC	5	2	11	136	9,657	201,373	77.8%	0.48	0.62	0.37	386	274	42,711	44,760	431	9,817	1,028	26,785

EMC ENGINEERS, INC.
PROJ. #_____ PROJECT 3102-022
SHEET NO. 5 OF ____
CALCULATED BY [illegible] DATE 1/29/92
CHECKED BY ______ DATE ______
SUBJECT __________

.NT

CONDITION		EXCESS LO PRES STEAM (LBM/HR)	EXCESS LO PRES VENT (LBM/HR)	PRV STEAM (LBM/HR)	TOTAL IN PLANT STEAM (LBM/HR)	TOTAL IN PLANT STEAM	STEAM TO LOAD (LBM/HR)	FUEL IN (MBH)	MONTHLY FUEL IN (MBH)	STEAM TO LOAD (MBH)	MAKE UP WATER (MBH)	CHP ENERGY ADDED (MBH)	CHP EFF	STEAM JET (MBH)	FLUE LOSS (MBH)	COMBUSTI LOSS (MBH)	EXCESS STEAM VENT (MBH)
BASECASE		555	555	0	26,691	16.49%	135,200	238.9	172,004	172	3	168	70.5%	1	41	19	0.642
DESIGN		(36,031)	0	36,031	100,568	15.71%	639,432	888.1	639,420	686	13	672	75.7%	1	118	72	0.000
AIR PREHEATER		(226)	0	226	26,033	16.15%	135,200	224.7	161,760	172	3	168	75.0%	1	29	18	0.000
	JAN	(4,655)	0	4,655	32,854	16.02%	172,191	281.3	209,251	219	4	215	76.3%	1	34	23	0.000
	FEB	(4,125)	0	4,125	31,874	16.04%	166,877	273.2	183,566	212	4	208	76.1%	1	33	22	0.000
	MAR	(2,201)	0	2,201	29,032	16.08%	151,466	249.6	185,730	193	4	189	75.6%	1	31	20	0.000
	APR	(800)	0	800	26,914	16.13%	139,980	232.0	167,055	178	3	174	75.2%	1	30	19	0.000
	MAY	870	870	0	24,928	16.78%	123,623	208.1	154,855	157	3	154	74.0%	1	28	17	1.006
	JUN	1,502	1,502	0	24,558	17.28%	117,555	199.7	143,795	149	3	146	73.3%	1	27	16	1.737
	JUL	1,571	1,571	0	24,517	17.34%	116,885	198.8	147,895	149	3	146	73.3%	1	27	16	1.818
	AUG	1,569	1,569	0	24,518	17.34%	116,907	198.8	147,918	149	3	146	73.3%	1	27	16	1.815
	SEP	1,338	1,338	0	24,655	17.15%	119,133	201.9	146,376	151	3	148	73.5%	1	27	16	1.548
	OCT	67	67	0	25,647	16.20%	132,672	220.9	164,331	169	3	166	74.8%	1	29	18	0.078
	NOV	(2,222)	0	2,222	29,062	16.08%	151,630	249.9	179,919	193	4	189	75.6%	1	31	20	0.000
	DEC	(4,056)	0	4,056	31,773	16.04%	166,331	272.3	202,615	211	4	207	76.1%	1	33	22	0.000
									2,032,305								

COMMENT #1

280°F Precipitators

% sulfur= 0.75% from coal analysis

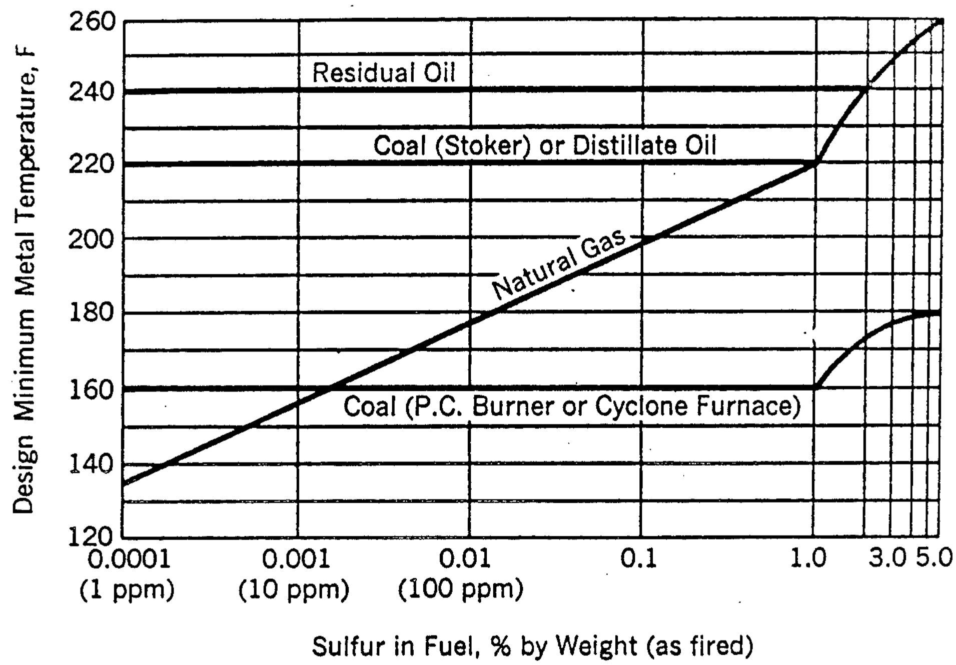


Fig. 4 Limiting tube-metal temperatures to avoid external corrosion in economizers or air heaters when burning fuels containing sulfur.

Minimum metal temperature = 220°F.

280°F provides 60°F safety margin.

EMC ENGINEERS, INC.
PROJ. #____ PROJECT 3102-[illegible]
SHEET NO. 5 OF 11
CALCULATED BY [illegible] DATE 7/[illegible]
CHECKED BY____ DATE____
SUBJECT____

ANALYSIS OF FAN CAPACITY

(From boiler model)

	ε	Fuel* (MBh)	Forced* Draft Fan (cfm)	Induced* Draft Fan (cfm)	% of Full Flow	% of Full Pressure	Static** Pressure Reduction (" w.c.)
Basecase	0	238.9	41,818	43,603	100	100	0
Preheater	0.32	224.7	39,410	41,092	94.2	88.8	5.6

*From Boiler Model
**Combined static pressure drop allowable for air preheaters.

Fans are designed for 52,500 cfm @ 550 hp.

$$HP = \frac{cfm \Delta p}{\eta_F 6350}.$$

$$\Delta p = \frac{HP\, x\, \mathrm{H}_F\, x\, 6350}{cfm} = \frac{550\ 0.75\ 6350}{52{,}500} = 49.9''\, H_2O.$$

$$\frac{p_1}{p_2} = \left(\frac{cfm_1}{cfm_2}\right)^2 \ \textit{Fan Laws}.$$

Fans are reported to be at maximum capacity and are the limiting factor for boiler operation. Air preheaters increase boiler efficiency and reduce fuel and air flow. Reduced air flow will offset the static pressure of the air preheater coils.

EMC ENGINEERS, INC.
PROJ. #_____ PROJECT _____
SHEET NO. _____ OF _____
CALCULATED BY _____ DATE _____
CHECKED BY _____ DATE _____
SUBJECT _____

FAX FROM

TROXLER ENGINEERING

Telephone (303) 779-5667 **FAX (303) 721-1151**

AEROFIN CORPORATION

8377 E. Hinsdale Drive
Englewood, Colorado 80112

Monday January 13, 1992

TO: Ron Gerrans - EMC Engineers, Inc.
2750 South Wadsworth Blvd., C-200
Denver, Colorado 80227-3493
Telephone: 988-2951
Telefax: 985-2527

EMC ENGINEERS, INC.
PROJ. #____ PROJECT ____
SHEET NO. 8 OF 11
CALCULATED BY ____ DATE ____
CHECKED BY ____ DATE 1/13/92
SUBJECT ____

SUBJECT: Heat Recovery Coil Loop

TOTAL NUMBER OF PAGES SENT = 2

Dear Ron:

The latest iteration follows and should be self explanatory. You will see that I ended up using a 36 tube face (54" casing height) x 7'-0" Nominal Tube Length (NTL) Exhaust Coil, and two 12 tube face (20-9/16" casing height) x 9'-6" NTL Make Up Air Coils.

I do not have the total flexibility desirable with the coil calculation program available, but it makes me feel that the performance can be achieved even though materials are different, and face velocities and fluid temperatures are quite high. In the event that this project goes ahead, we should take a close look at:

Larger face areas to reduce face velocity and possible erosion.
Materials of construction...stainless steel, std. steel?
Fluid medium...Therminol, etc.?
Fin spacing...12.5 fpi now. 10 fpi?

For now I have developed budget pricing as follows:

CONSTRUCTION	Steel Tubes, 0.049" wall, welded joints. L-footed aluminum fins. Raised face flange connections.
BUDGET PRICING	(1) 36 TF x 7'-0" NTL, 4 row coil.....$ 9,700.00 (2) 12 TF x 9'-6" NTL, 4 row coils....$ 10,600.00

Sincerely,

TROXLER ENGINEERING
Sales Representatives for the
AEROFIN CORPORATION

Fred

By: C. G. Troxler

EMC ENGINEERS, INC.
PROJ. #______ PROJECT ______
SHEET NO. 7 OF 11
CALCULATED BY ______ DATE ______
CHECKED BY ______ DATE 1/24/92
SUBJECT ______

COMPUTER SELECTION OF AEROFIN HEAT RECOVERY COILS HRRA rE -369-

Job Name : EMC ENGINEERS
Quote Number : RON GERRANS
System Id :
Date : 01/13/92

Coil Information	Exhaust	Make-Up
Coil Type :	C	C
Fin Material :	Copper Solder Coated	Copper Solder Coated
Coil Circuit :	FULL	FULL
Tube Size :	5/8" x 0.049" wall	5/8" x 0.049" wall
Number In Face :	1	2
Tube Face :	36	12
N. Tube Length :	7'0	9'6
Fin Series :	140	140
Fins Per Inch :	12.5	12.5
Rows :	4	4
System Face Area :	28.8 sq ft	26.3 sq ft
Coil Dry Weight :	1032 lbs	512 lbs

Performance - Total Heat Recovered 4622.0 MBH Efficiency 31.8%

	Exhaust	Make-Up
Air Side		
Elevation :	0 ft	0 ft
Standard Pressure :	29.92 in Hg	29.92 in Hg
Standard Airflow :	42065 cfm	40339 cfm
Standard Face Velocity :	1462 fpm	1531 fpm
Entering Dry Bulb Temperature :	388.0 F	56.0 F
Entering Wet Bulb Temperature :	---	---
Leaving Dry Bulb Temperature :	287.2 F	161.7 F
Leaving Wet Bulb Temperature :	---	---
Outside Surface Fouling :	0.0100	0.0100
Fluid Side - Water		
Entering Temperature :	183.3 F	280.6 F
Leaving Temperature :	280.6 F	183.3 F
Flow Rate :	100.0 gpm	100.0 gpm
Tube Velocity :	4.1 fps	6.1 fps
Inside Surface Fouling :	0.0000	0.0000
Losses		
Air Friction :	2.83 in wg	2.17 in wg
Fluid Pressure Drop :	7.1 ft wg	13.9 ft wg

Notes
- EM Entering fluid temperature > program limit 180 °F.
- E The use of safety pressure relief valve is advised.
- M Coil weight shown is for one coil.
- EM Temperatures exceed standard coil design temp. Contact Home Off.

ENGINEERS OPINION OF PROBABLE COST

Project	Holston Army Ammunition Plant Limited Energy Studies – DACA01-91-D-0032	SHEET 1○OF 11 DATE PREPARED 07/16/92
Engineer	EMC Engineers, Inc – PN# 3102-002 Denver, CO	Estimator
Description	AREA B AIR PREHEATER	Checked by

Description	Quantity No. Units	Quantity Unit Meas.	Material Per Unit	Material Total	Labor Hours Per Unit	Labor Hourly Rate	Labor Total	Total Cost
Tee-Reducing, 8"	1	EA	$185.00	$185	8	$16.89	$135	$320
Pipe, sch 40, 3"	200	LF	$6.72	$1,344	0.372	$16.89	$1,257	$2,601
Elbow	20	EA	$19.60	$392	1.6	$16.89	$540	$932
Tee	2	EA	$26.00	$52	2.667	$16.89	$90	$142
Valve-Globe	1	EA	$240.00	$240	2	$16.89	$34	$274
Unions	6	EA	$37.00	$222	1.778	$16.89	$180	$402
Flex Hose	2	EA	$202.00	$404	1.143	$16.89	$39	$443
Air Seperator	1	EA	$815.00	$815	1.231	$16.89	$21	$836
Insulation, FG/ASJ, 3"Dx2"W	200	LF	$4.83	$966	0.1	$16.89	$338	$1,304
Pipe, sch 40, 1"	30	LF	$1.54	$46	0.151	$16.89	$77	$123
Elbow	5	EA	$1.85	$9	0.615	$16.89	$52	$61
Tee	1	EA	$3.00	$3	1	$16.89	$17	$20
Insulation, FG/ASJ, 1"Dx2"W	30	LF	$3.59	$108	0.08	$16.89	$41	$148
Expansion Tank	1	EA	$325.00	$325	1.6	$16.89	$27	$352
Pump	1	EA	$955.00	$955	8	$16.89	$135	$1,090
Reclaim Coil	1	EA	$10,600.00	$10,600	24	$16.89	$405	$11,005
Preheat Coil	1	EA	$9,700.00	$9,700	24	$16.89	$405	$10,105
Relief Valve	1	EA	$745.00	$745	1.6	$16.89	$27	$772
Wire – #12	4	CLF	$7.75	$31	0.727	$16.19	$47	$78
Conduit – 1/2"	100	LF	$2.70	$270	0.1	$16.19	$162	$432
Motor Starter	1	EA	$480.00	$480	4.444	$16.19	$72	$552
SUBTOTAL				$27,707			$3,965	$31,992
OVERHEAD & BOND	0.16			$4,433			$634	$5,119
SUBTOTAL				$32,140			$4,599	$37,111
PROFIT	0.1			$3,214			$460	$3,711
SUBTOTAL				$35,354			$5,059	$40,822
CONTINGENCY	0.2			$7,071			$1,012	$8,164
TOTAL ESTIMATED COST				$42,425			$6,071	$48,987

X 4 BOILERS = $195,947

LIFE CYCLE COST ANALYSIS SUMMARY
ENERGY CONSERVATION INVESTMENT PROGRAM (ECIP)

LOCATION:	HOLSTON AAP	REGION:	4
PROJ. NO. & TITLE:	DACA01-91-D-0032 LIMITED ENERGY STUDIES		
DISCRETE PORTION:	AREA B AIR PREHEATER		
FISCAL YEAR:	91	ECONOMIC LIFE	25
ANALYSIS DATE:	16-Jul-92	PREPARED BY: D JONES	

1 INVESTMENT

A.	CONSTRUCTION COST	=	$195,948
B.	SIOH COST	(5.5% of 1A) =	$10,777
C.	DESIGN COST	(6.0% of 1A) =	$11,757
D.	SALVAGE VALUE	=	$0
E.	TOTAL INVESTMENT	(1A + 1B +1C +1D – 1E) =	$218,482

2 ENERGY SAVINGS (+) / COST (–)

	FUEL TYPE	FUEL COST $/MBTU (1)	SAVINGS MBTU/YR (2)	ANNUAL $ SAVINGS (3)	DISCOUNT FACTOR (4)	DISCOUNTED SAVINGS (5)
A.	ELEC	$4.67	(10)	($44)	15.61	($693)
B.	DIST		0	$0	0.00	$0
C.	RESID		0	$0	0.00	$0
D.	NAT GAS		0	$0		$0
E.	COAL	$1.25	123,249	$154,061	16.06	$2,474,224
F.	TOTAL ENERGY SAVINGS		123,240	$154,017		$2,473,531

3 NON-ENERGY SAVINGS (+) / COST (–)

A. ANNUAL RECURRING

	ANNUAL $	DISCOUNT FACTOR	DISCOUNTED SAVINGS
ADDED MAINTENANCE COST	($1,000)	14.53	($14,530)
ELECTRIC DEMAND SAVINGS (0)KW * $9.50/KW/MTH * 12 MTHS =	($36)	14.53	($525)
TOTAL SAVINGS (+) / COST (–)	($1,036)		($15,055)

B. NON-RECURRING (+/–)

ITEM	YEAR OF OCCURRENCE	ANNUAL $	DISCOUNT FACTOR	DISCOUNTED SAVINGS
a.		$0	0.00	$0
b.		$0	0.00	$0
c.		$0	0.00	$0
TOTAL SAVINGS (+) / COST (–)		$0		$0

C. TOTAL NON ENERGY DISCOUNTED SAVINGS (3A + 3B) — ($15,055)

D. PROJECT NON-ENERGY QUALIFICATION TEST
NON ENERGY SAVINGS % (3C / (3C + 2F)) — -1%

4 FIRST YEAR DOLLAR SAVINGS (+) / COSTS (–)	$152,981
5 TOTAL NET DISCOUNTED SAVINGS	$2,458,476
6 DISCOUNTED SAVINGS-TO-INVESTMENT RATIO (SIR)	11.25
7 SIMPLE PAYBACK (YEARS)	1.43

APPENDIX G

AREA-B BLOWDOWN HEAT EXCHANGER ANALYSIS

EMC ENGINEERS, INC.
PROJ. #______ PROJECT ______
SHEET NO. __1__ OF ______
CALCULATED BY ______ DATE ______
CHECKED BY ______ DATE ______
SUBJECT ______

EXISTING CONDITION

BLOWDOWN MEASURED AT 2.5% OF STEAM PRODUCTION

AREA B PEAK STEAM DEMAND = 241,300 LBM/HR
(SEE APPENDIX B, PAGE 36)

PEAK STEAM PRODUCTION = 241,300/0.83 = 290,700 LBM/HR

17% IN PLANT USE

BLOWDOWN = 2.5% × 290,700 = 7,268 LBM/HR

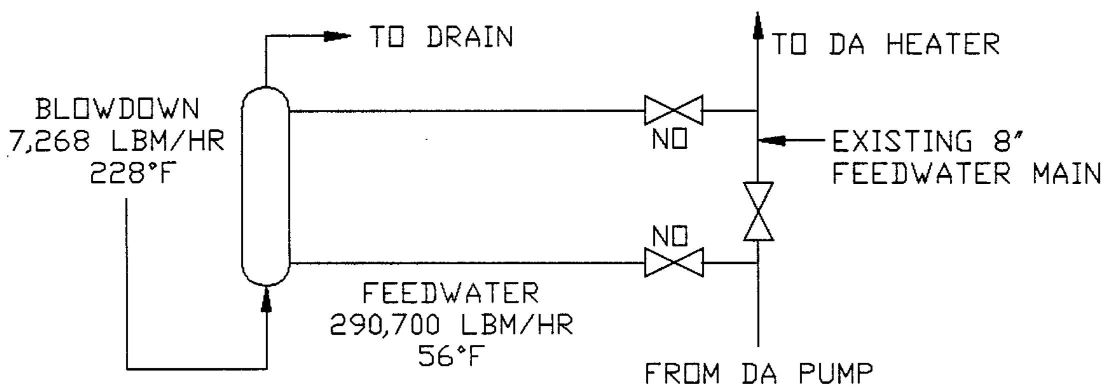
21.1% OF BLOWDOWN FLASHES TO STEAM AND IS ROUTED TO LOW PRESSURE HEADER

BLOWDOWN LIQUID = 78.9% × 7,268 = 5,734 LBM/HR

PROPOSED MODIFICATION

INSTALL HEAT EXCHANGER TO USE HEAT FROM BLOWDOWN LIQUID TO HEAT FEEDWATER.

DESIGN FOR CURRENT PEAK STEAM PRODUCTION



DESIGN FOR 80% HTX EFFECTIVENESS

$$Q = E\ \mathring{m}_{BD}\, C_P\, (T_H - T_C)$$

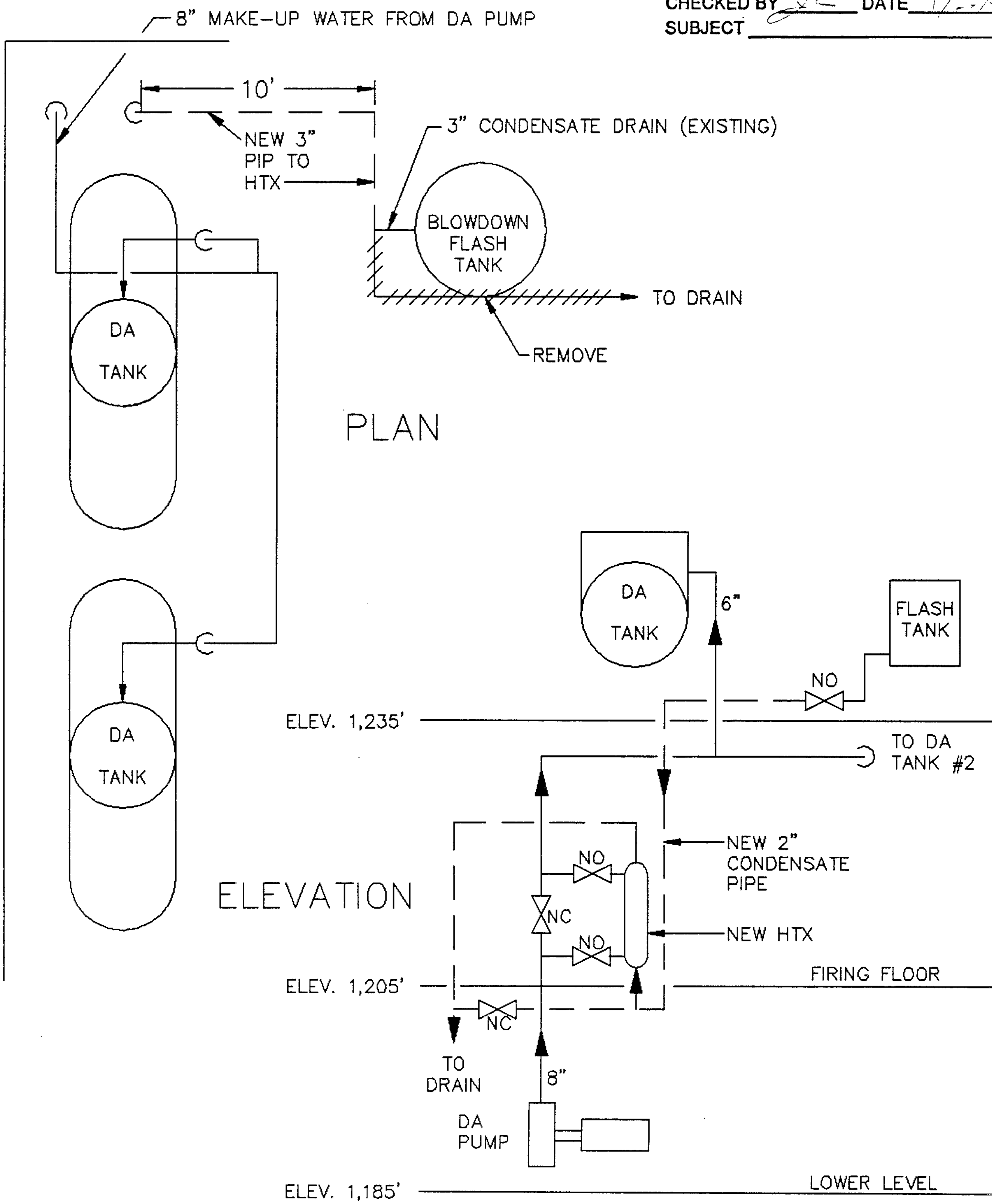
$$= 0.8 \times 7{,}268\ \text{LBM/HR} \times 1\ \text{BTU/LBM°F} \times (228°F - 56°F) = 1{,}000{,}000\ \text{BTU/HR}$$

FEEDWATER EXIT TEMP

$$T_E = T_I + \frac{Q}{\mathring{m}_{FW}\, C_P} = 56°F + \frac{1\text{E}6\ \text{BTU}}{\text{HR}} \cdot \frac{\text{HR}}{290{,}700\ \text{LBM}} \times \frac{\text{LBM°F}}{1\ \text{BTU}} = \boxed{59.4°F}$$

EMC ENGINEERS, INC.
PROJ. #______ PROJECT ______
SHEET NO. 2 OF ______
CALCULATED BY ______ DATE ______
CHECKED BY ______ DATE ______
SUBJECT ______

BLOWDOWN HTX DESIGN



EMC ENGINEERS, INC.
PROJ. # ______ PROJECT ______
SHEET NO. ______ OF ______
CALCULATED BY ______ DATE ______
CHECKED BY ______ DATE ______
SUBJECT ______

DESIGN

SIZE HEAT EXCHANGER

SHELLSIDE – BLOWDOWN WATER

7,268 LBM/HR/500 ≈ 15 GPM
228°F EWT

TUBESIDE – FEEDWATER

290,700 LBM/HR/500 ≈ 600 GPM
56°F → 59.4°F

SELECT TACO G16206-6L

PIPING

BLOWDOWN WATER 15 GPM → 2" PIPE
FEEDWATER 600 GPM → 6" PIPE

ENERGY SAVINGS

BASECASE	2,155,572 MBTU COAL USAGE
MODIFIED	2,153,016 MBTU COAL USAGE
SAVINGS	2,556 MBTU/YR

MAINTENANCE

16 HRS/YR @ $25 = $400/YR

EMC ENGINEERS, INC.
PROJ. #______ PROJECT 310-...
SHEET NO. 4 OF 12
CALCULATED BY______ DATE 1/29/92
CHECKED BY______ DATE______
SUBJECT______

AREA-B COMPUTER BOILER MODEL - BLOWDOWN HEAT RECOVERY

BLWDNECO

HEATING VALUE OF COAL	HHV	14100.00	BTU/LBM	COAL ANALYSIS
THEORETICAL COMBUSTION AIR	THEO	11.00	LBM/LBM	LBH AIR/LBH COAL FROM ASHRAE FUNDAMENTALS
MIXED WATER TEMP	RETURN	56.00	F	LBH OF 5 PSI STEAM CONDENSED PER LBH OF MAKE UP
LATENT HEAT (5 PSI)	PSI5	960.00	BTU/LBM	STEAM TABLES
ECONOMOZER AIR TEMP IN	TEI	480	F	MEASURED
ECONOMIZER UA	ECON	25000.00	BTUH/F	AREA-A ECONOMIZER ANALYSIS
BLOWDOWN RATE	BLOW	2.46%	%	MEASURED
STEAM ENTHALPY	HS	1271.00	BTU/LBM	300 PSI, 525 F
LIQUID ENTHALPY	HL	399	BTU/LBM	300 PSI, SATURATED
LOW PRES STEAM ENTHALPY	HSLP	1,157	BTU/LBM	5 PSIG, SAT
DA HEATER LIQUID ENTHALPY	HLDA	196	BTU/LBM	228 F, SAT
AMBIENT TEMPERATURE	TA	56	F	WEATHER DATA
COMBUSTION LOSSES	LOSS	8.10%	%	ASSUMED
RADIATION LOSSES PER BOILER	RAD	1.65	MMBH	ASSUMED
DESIGN FAN HORSEPOWER	FANHP	550	HP	DESIGN DATA
DESIGN FAN CFM	FANCFM	52,500	CFM	DESIGN DATA
FAN STEAM RATE	FANSTM	21.60	LBH/HP	TURBINE MANUFACTURER
DA PUMP DESIGN HORSEPOWER	DAHP	80	HP	DESIGN DATA
DA PUMP DESIGN FLOW	DAGPM	1,750	GPM	DESIGN DATA
DA PUMP STEAM RATE	DASTM	54.8	LBH/HP	TURBINE MANUFACTURER
FW PUMP DESIGN HORSEPOWER	FWHP	135	HP	DESIGN DATA
FW PUMP DESIGN FLOW	FWGPM	460	GPM	DESIGN DATA
FW PUMP STEAM RATE	FWSTM	33.4	LBH/HP	TURBINE MANUFACTURER
BLOWDOWN FLASH STEAM	FLASH	21.10%	%	CALCULATED
FW PUMP HEAD	FWHEAD	700	FT	CALCULATED
VACUUM STEAM JET RATE	JET	932	LBH	CALCULATED
INTERMEDIATE HEADER PRESSU	IHP	5	PSIG	
INTERMEDIATE HEADER TEMP	IHT	228	F	
PRE-HEATER EFFECTIVENESS	IHE	0.80		
PRE-HEATER LATENT HEAT	IHH	960	BTU.LBM	
LOW PRESSURE STEAM TEMP	LPT	228	F	

							BLOWDOWN HEAT RECOVERY				DEAERATING HEATER			DA PUMPS			FEEDWATER PUMP	
CONDITION	NUMBER OF DAYS	CHP STEAM DEMAND (LBM/HR)	CHP STEAM BALANCE (LBM/HR)	BOILER STEAM FLOW (LBM/HR)	BOILERS ON LINE	TOTAL FEED WATER (LBM/HR)	BLOW DOWN LIQUID (LBM/HR)	HEAT EXCHANGE EFF	HEAT TRANSFER (BTUH)	LEAVING MAKE UP TEMP (F)	5 PSI STEAM (LBM/HR)	MAKE UP WATER (LBM/HR)	LEAVING MAKE UP TEMP (F)	DA PUMP FLOW (GPM)	DA PUMP POWER (HP)	DA PUMP STEAM (LBM/HR)	FW PUMP FLOW (GPM)	FW PUMP POWER (HP)
BASECASE	30	135,200	2	161,892	2	165,874	3,142	0.80	432,369	59	24,821	141,063	228	283	36	2,472	333	84
DESIGN	30		640,942	640,000	4	655,744	12,422	0.80	1,709,269	59	98,126	557,618	228	1,120	67	3,826	1,317	333
JAN	31	172,191	0	204,474	2	209,504	3,969	0.80	546,094	59	31,350	178,154	228	358	40	2,616	421	106
FEB	28	166,877	0	198,197	2	203,073	3,847	0.80	529,332	59	30,388	172,685	228	347	36	2,472	408	103
MAR	31	151,466	0	179,996	2	184,423	3,494	0.80	480,720	59	27,597	156,826	228	315	36	2,472	370	94
APR	30	139,980	0	166,954	2	171,061	3,240	0.80	445,889	59	25,597	145,463	228	292	36	2,472	343	87
MAY	31	123,623	0	149,431	2	153,107	2,900	0.80	399,092	59	22,911	130,197	228	261	32	2,301	307	78
JUN	30	117,555	0	142,981	2	146,498	2,775	0.80	381,864	59	21,922	124,576	228	250	32	2,301	294	74
JUL	31	116,885	(0)	142,268	2	145,768	2,761	0.80	379,960	59	21,813	123,955	228	249	32	2,301	293	74
AUG	31	116,907	(0)	142,292	2	145,792	2,762	0.80	380,023	59	21,816	123,976	228	249	32	2,301	293	74
SEP	30	119,133	(0)	144,659	2	148,218	2,808	0.80	386,347	59	22,179	126,039	228	253	32	2,301	298	75
OCT	31	132,672	0	159,214	2	163,131	3,090	0.80	425,219	59	24,411	138,720	228	279	36	2,472	328	83
NOV	30	151,630	0	180,189	2	184,622	3,497	0.80	481,237	59	27,627	156,995	228	315	36	2,472	371	94
DEC	31	166,331	0	197,552	2	202,412	3,834	0.80	527,610	59	30,289	172,123	228	346	36	2,472	406	103

AREA-B COMP BOILER MODEL - BLOWDOWN HEAT RECOVERY

EMC ENGINEERS, INC.
PROJ. #____ PROJECT 3102-002
SHEET NO. 5 OF 12
CALCULATED BY____ DATE 1/27/92
CHECKED BY____ DATE____
SUBJECT____

BLWDNECO DA PUMP CURVE

GPM	HEAD	EFF	HP	PLR	%HP
0	218	0%	0	0%	0%
100	218	16%	34	5%	34%
200	218	27%	41	10%	41%
300	217	36%	46	15%	46%
400	217	44%	50	20%	50%
600	215	55%	59	30%	59%
800	214	63%	69	40%	68%
1,000	211	70%	76	50%	76%
1,200	209	75%	84	60%	84%
1,400	202	80%	89	70%	89%
1,600	193	84%	93	80%	92%
1,800	184	86%	97	90%	97%
2,000	173	87%	100	100%	100%
2,400	146	85%	103	120%	103%
2,800	90	74%	86	140%	86%

PART LOAD	STEAM OUT	BLOWDOW	DRY FLUE L	FLUE HUMI	RADIATION	COMBUSTION LOSS
BASECASE	72.52%	0.67%	13.44%	3.89%	1.38%	8.10%
DESIGN	77.12%	0.71%	9.43%	3.89%	0.74%	8.10%

		STEAM PRE-HEATER			COMBUSTION AIR PREHEAER				BOILER INCLUDING ECONOMIZER									
CONDITION	FW PUMP STEAM (LBM/HR)	HEAT TRANSFER (BTUH)	STEAM DEMAND (LBM/HR)	LEAVING FW TEMP (F)	HEAT EXCHANGE EFF	ENERGY EXCHANGE (BTUH)	PRE HEAT EXIT (F)	FLUE GAS EXIT (F)	STEAM OUT (LBM/HR)	BOILER FEED WATER (LBM/HR)	ESTMTD OXYGEN	PERCENT EXCESS AIR	COMBUST AIR FLOW (LBM/HR)	STEAM OUT (MBH)	FDW IN (MBH)	STEAM PRODUCED (MBH)	BLOW DOWN LOSS (MBH)	DRY FLUE LOSS (MBH)
BASECASE	3,149	564	1	228	0.00	0	56	386	80,946	82,937	10.60%	102%	188,181	103	16	87	1	16
DESIGN	9,787	0	0	228	0.00	0	56	398	160,000	163,936	6.33%	34%	232,093	203	32	171	2	21
JAN	3,740	(419)	(0)	228	0.00	0	56	390	102,237	104,752	9.18%	78%	204,526	130	21	109	1	18
FEB	3,663	(406)	(0)	228	0.00	0	56	390	99,099	101,536	9.39%	81%	202,412	126	20	106	1	18
MAR	3,401	(369)	(0)	228	0.00	0	56	388	89,998	92,212	10.00%	91%	195,741	114	18	96	1	17
APR	3,220	1,042	1	228	0.00	0	56	386	83,477	85,530	10.43%	99%	190,398	106	17	89	1	16
MAY	2,976	935	1	228	0.00	0	56	384	74,716	76,554	11.02%	110%	182,337	95	15	80	1	15
JUN	2,887	894	1	228	0.00	0	56	383	71,490	73,249	11.23%	115%	179,076	91	14	77	1	15
JUL	2,877	890	1	228	0.00	0	56	383	71,134	72,884	11.26%	116%	178,705	90	14	76	1	15
AUG	2,877	890	1	228	0.00	0	56	383	71,146	72,896	11.25%	116%	178,717	90	14	76	1	15
SEP	2,910	905	1	228	0.00	0	56	383	72,330	74,109	11.18%	114%	179,941	92	15	77	1	15
OCT	3,112	995	1	228	0.00	0	56	385	79,607	81,565	10.69%	104%	186,972	101	16	85	1	16
NOV	3,403	(369)	(0)	228	0.00	0	56	388	90,096	92,311	9.99%	91%	195,816	115	18	96	1	17
DEC	3,644	(405)	(0)	228	0.00	0	56	390	98,776	101,206	9.41%	81%	202,190	126	20	106	1	18

AREA-B COMPUTER BOILER MODEL - BLOWDOWN HEAT RECOVERY

BLWDNECO	DA PUMP	FW PUMP	DRAFT FAN	MISCELLAN	STEAM TO LOAD
	2,472	3,149	19,297	1,772	136,202

EMC ENGINEERS, INC.
PROJ. #_____ PROJECT 3151-02
SHEET NO. 5 OF 12
CALCULATED BY [illegible] DATE 1/29/92
CHECKED BY_____ DATE_____
SUBJECT_____

									ECONOMIZER					DRAFT FANS				CENTRAL HEATING PLA	
CONDITION		FUEL HUMIDITY LOSS (MBH)	RADIATION LOSS (MBH)	COMBUST LOSSES (MBH)	FUEL IN (MBH)	COAL FLOW (LBM/HR)	FLUE GAS FLOW (LBM/HR)	BOILER EFF	CAPACITY RATIO	NTU	EFF	EXIT AIR (F)	EXIT WATER (F)	FORCED DRAFT (SCFM)	INDUCED DRAFT (SCFM)	TOTAL HP	FAN STEAM (LBM/HR)	BLOW DOWN FLASH (LBM/HR)	TOTAL LO PRES STEAM (LBM/HR)
BASECASE		5	2	10	119	8,471	196,229	72.5%	0.67	0.63	0.37	386	283	41,818	43,606	421	9,649	840	25,758
DESIGN		9	2	18	222	15,746	247,052	77.1%	0.36	0.42	0.33	398	259	51,676	54,900	538	11,668	3,322	63,605
	JAN	6	2	12	148	10,465	214,468	74.2%	0.49	0.49	0.36	390	273	45,450	47,660	462	10,353	1,061	28,124
	FEB	6	2	12	143	10,173	212,076	73.9%	0.50	0.49	0.36	390	276	44,980	47,128	466	10,268	1,029	27,671
	MAR	5	2	11	131	9,323	204,598	73.3%	0.53	0.51	0.37	388	279	43,498	45,466	439	9,967	934	26,741
	APR	5	2	10	123	8,710	198,673	72.7%	0.56	0.52	0.37	386	282	42,311	44,150	426	9,741	867	26,038
	MAY	4	2	9	111	7,880	189,823	72.0%	0.60	0.55	0.38	384	287	40,519	42,183	407	9,411	776	24,873
	JUN	4	2	9	107	7,573	186,270	71.7%	0.61	0.56	0.38	383	289	39,796	41,393	400	9,281	742	24,491
	JUL	4	2	9	106	7,539	185,867	71.6%	0.61	0.56	0.39	383	289	39,712	41,304	399	9,266	738	24,448
	AUG	4	2	9	106	7,540	185,880	71.6%	0.61	0.56	0.38	383	289	39,715	41,307	399	9,267	739	24,450
	SEP	4	2	9	108	7,653	187,211	71.7%	0.61	0.56	0.38	383	289	39,987	41,603	402	9,315	751	24,591
	OCT	5	2	10	118	8,345	194,900	72.4%	0.57	0.53	0.38	385	284	41,549	43,311	418	9,599	826	25,607
	NOV	5	2	11	132	9,332	204,682	73.3%	0.53	0.51	0.36	388	279	43,515	45,485	440	9,971	935	26,752
	DEC	6	2	12	143	10,143	211,826	73.9%	0.50	0.49	0.36	390	276	44,931	47,072	456	10,249	1,025	27,639

AREA-B COM BOILER MODEL - BLOWDOWN HEAT RECOVERY

BLWDNECO

EMC ENGINEERS, INC.
PROJ. #_____ PROJECT 315 002
SHEET NO. 7 OF 12
CALCULATED BY ____ DATE ____
CHECKED BY ____ DATE ____
SUBJECT ____

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CONDITION		EXCESS LO PRES STEAM (LBM/HR)	EXCESS LO PRES VENT (LBM/HR)	PRV STEAM (LBM/HR)	TOTAL IN PLANT STEAM (LBM/HR)	TOTAL IN PLANT STEAM	STEAM TO LOAD (LBM/HR)	FUEL IN (MBH)	MONTHLY FUEL IN (MBH)	STEAM TO LOAD (MBH)	MAKE UP WATER (MBH)	CHP ENERGY ADDED (MBH)	CHP EFF	STEAM JET (MBH)	FLUE LOSS (MBH)	COMBUSTI LOSS (MBH)	EXCESS STEAM VENT (MBH)
BASECASE		937	937	0	26,690	16.49%	135,202	238.9	172,003	172	3	168	70.6%	1	41	19	1.084
DESIGN		(34,521)	0	34,521	99,058	15.48%	640,942	888.1	639,420	688	13	674	75.9%	1	118	72	0.000
	JAN	(3,226)	0	3,226	32,283	15.79%	172,191	295.1	219,557	219	4	215	72.7%	1	47	24	0.000
	FEB	(2,717)	0	2,717	31,320	15.80%	166,877	286.9	192,784	212	4	208	72.6%	1	46	23	0.000
	MAR	(856)	0	856	28,530	15.86%	151,466	262.9	195,613	193	4	189	71.8%	1	44	21	0.000
	APR	441	441	0	26,974	16.16%	139,980	245.6	176,857	178	3	174	71.0%	1	42	20	0.610
	MAY	1,962	1,962	0	25,808	17.27%	123,623	222.2	165,337	157	3	154	69.3%	1	40	18	2.270
	JUN	2,569	2,569	0	25,426	17.78%	117,555	213.5	153,756	149	3	146	68.6%	1	39	17	2.972
	JUL	2,636	2,636	0	25,383	17.84%	116,885	212.6	158,166	149	3	146	68.6%	1	38	17	3.049
	AUG	2,633	2,633	0	25,385	17.84%	116,907	212.6	158,189	149	3	146	68.6%	1	38	17	3.047
	SEP	2,412	2,412	0	25,526	17.65%	119,133	216.8	155,384	151	3	148	68.8%	1	39	17	2.791
	OCT	1,196	1,196	0	26,542	16.67%	132,672	236.3	175,080	169	3	166	70.2%	1	41	19	1.384
	NOV	(875)	0	875	28,559	15.85%	151,630	263.2	189,487	193	4	189	71.8%	1	44	21	0.000
	DEC	(2,650)	0	2,650	31,221	15.80%	166,331	286.0	212,810	211	4	207	72.6%	1	46	23	0.000
									2,163,019								

EMC ENGINEERS, INC.
PROJ. #______ PROJECT ________
SHEET NO. 8 OF 12
CALCULATED BY______ DATE______
CHECKED BY______ DATE______
SUBJECT ______

McCOY
SALES CORPORATION

DATE: 7/17/92

TO: EMC. Eng.

ATTN: Dennis Jones 985-2527

FROM: Nick

TOTAL NO. OF PAGES (INCLUDING THIS PAGE) 2

RE: TACO G16206-6L
COPPER TUBES
STEEL SHELL
STEEL HEAD
STEEL TUBESHEET

$ 4500.00 - 5000.00
745#

FAX: (303) 781-7362

MANUFACTURERS' REPRESENTATIVE
2190 W. BATES AVE. • ENGLEWOOD, CO 80110 • (303) 762-8012

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PROJ. #______ PROJECT ______
SHEET NO. ______ OF ______
CALCULATED BY ______ DATE ______
CHECKED BY ______ DATE ______
SUBJECT ______

Taco Submittal Data Information U Tube Heat Exchangers

201-013

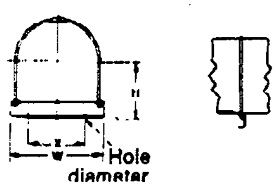
16" DIAMETER LIQUID

SUPERSEDES: SD200-2

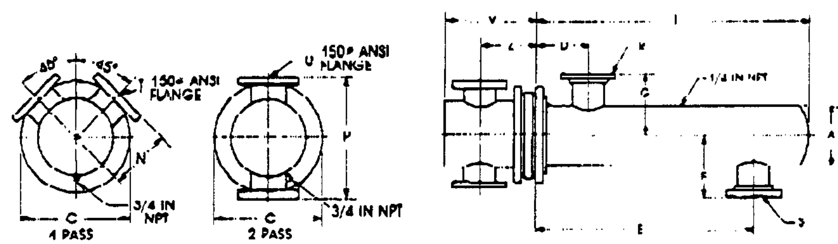
Job: ______

Item No.	Model No.	Pass	GPM Tubes	Temp. In	Temp. Out	P.D. Tubes	Vel. Tubes	GPM Shell	Temp. In	Temp. Out	P.D. Shell	Vel. Shell
	G16206L	2	600	56 °F	59.4 °F	3.15'	5.76 FPS	15	228 °F	96.3 °F	.01'	.18 FPS

Tube Fluid ______ Shell Fluid ______



SADDLES
(Optional)



DIMENSIONS

16 Inch Diameter

Model Number		Fabricated Steel Heads								Dimensions (Inches)									Heating Surface (sq.ft.)	Shipping Weight (lbs.)
2 Pass	4 Pass	2 Pass P	U	V	Z	4 Pass N	T	V	Z	2 and 4 Pass A	C	D	E	F	G	L	R	S		
G16206L	G16406L	28½	6F	19⅝	13⅜	14¼	4F	17⅜	12⅛	16	23½	9¾	25½	14½	14½	37	8F	8F	104.5	745
G16208L	G16408L	28½	6F	19⅝	13⅜	14¼	4F	17⅜	12⅛	16	23½	9¾	37½	14½	14½	49	8F	8F	141.4	863
C16210L	G16410L	28½	6F	19⅝	13⅜	14¼	4F	17⅜	12⅛	16	23½	9¾	49½	14½	14½	61	8F	8F	178.4	981
G16212L	G16412L	28½	6F	19⅝	13⅜	14¼	4F	17⅜	12⅛	16	23½	9¾	61½	14½	14½	73	8F	8F	215.3	1105
G16214L	G16414L	28½	6F	19⅝	13⅜	14¼	4F	17⅜	12⅛	16	23½	9¾	73½	14½	14½	85	8F	8F	252.2	1187
G16216L	G16416L	28½	6F	19⅝	13⅜	14¼	4F	17⅜	12⅛	16	23½	9¾	85½	14½	14½	97	8F	8F	289.1	1305
G16218L	G16418L	28½	6F	19⅝	13⅜	14¼	4F	17⅜	12⅛	16	23½	9¾	97½	14½	14½	109	8F	8F	326.0	1424
G16220L	G16420L	28½	6F	19⅝	13⅜	14¼	4F	17⅜	12⅛	16	23½	9¾	109½	14½	14½	121	8F	8F	363.0	1541

SADDLE DIMENSIONS: H-12; W-19; X-13; Hole Dia.-¾.

MATERIALS OF CONSTRUCTION (Unless otherwise indicated, standard will be furnished.)

	Standard	Optional
Shell	Steel	304ss, 316ss
Head	Cast Iron 4-10" Fabricated Steel 12-30"	Fabricated Steel, Cast Bronze, Fabricated 304ss/316ss Cast Bronze, Fabricated 304ss/316ss
Tubes	3/4 x 20 BWG Copper	3/4 x 18 BWG Copper, Steel, 304ss, 316ss, 90/10 Cu Ni, Admiralty
Tube Sheet	Steel	Bronze, Brass, 304ss, 316ss, 90/10 Cu Ni
Separators	Steel	Bronze, Brass, 304ss, 316ss, 90/10 Cu Ni
Working Pressure	150 PSIG (ASME)	Consult Factory
Max. Temperature	375°F	Consult Factory

Quality Through Design — COMPARE.

TACO, Inc., 1160 Cranston St., Cranston, RI 02920 (401) 942-8000 Telex: 92-7627
TACO, (Canada) Ltd., 1310 Aimco Blvd., Mississauga, Ontario L4W 1B2 (416) 625-2160 Telex: 06-961179

Form No. F201-013 Effective 10/1/84

EMC ENGINEERS, INC.
PROJ. #______ PROJECT ______
SHEET NO. ____ OF ____
CALCULATED BY ____ DATE ____
CHECKED BY ____ DATE ____
SUBJECT ______

Saturday, July 18, 1992

Taco, Inc.
TACO HEAT EXCHANGER SELECTION, Version 3.00
Job Name: EMC ENGINEERS
User ID: DENNIS JONES

** INPUT PARAMETERS **

Tubeside		Shellside	
Fluid Type: Water		Fluid Type: Water	
Flow Rate (gpm):	600.00	Flow Rate (gpm):	15.00
Entering Temp. (°F):	56.0	Entering Temp. (°F):	228.0
Leaving Temp. (°F):	59.4	Leaving Temp. (°F):	96.3
Fouling:	0.0005	Fouling:	0.0000
Load (MBh):	988.34	Load (MBh):	982.18

Tube Material: Copper .035 Wall
Maximum Length (ft): 10.0
LMTD: 88.8

** SELECTION RESULTS **

Model Num.	Dia. (in)	Num. Passes	Length (ft)	Baff. Pitch	Tube Vel.(fps)	Tube Pd.(ft)	Shell Vel.(fps)	Shell Pd.(ft)
G16206- 6L	16	2	3	6	5.76	3.15	0.18	0.01
G18206- 4L	18	2	3	4	4.49	1.95	0.24	0.01
G22408- 9L	22	4	4	9	5.82	9.27	0.10	0.00
G22208- 9L	22	2	4	9	2.91	0.95	0.10	0.00
G24408- 8L	24	4	4	8	4.73	6.20	0.10	0.00
C24208- 8L	24	2	4	8	2.37	0.64	0.10	0.00
G26408- 6L	26	4	4	6	3.90	4.26	0.13	0.00
G26208- 6L	26	2	4	6	1.95	0.44	0.13	0.00
C30410-12L	30	4	5	12	2.93	2.67	0.05	0.00
G30210-12L	30	2	5	12	1.46	0.29	0.05	0.00

ENGINEERS OPINION OF PROBABLE COST

Project	Forts McPherson and Gillem EEAP Study DACA21-91-C-0097	SHEET OF	DATE PREPARED 07/17/92
Engineer	EMC Engineers, Inc – PN# 3105-000 Atlanta, GA		Estimator D JONES
Description	AREA B BLOWDOWN HEAT EXCHANGER		Checked by

Description	Quantity		Material		Labor			Total Cost
	No. Units	Unit Meas.	Per Unit	Total	Hours Per Unit	Hourly Rate	Total	
HEAT EXCHANGER	1	EA	$5,000.00	$5,000	4	$16.89	$68	$5,068
FEEDWATER PIPING								
8" STEEL TEE	2	EA	$340.00	$680	2.667	$16.89	$90	$770
6" STEEL PIPE	20	LF	$19.64	$393	0.96	$16.89	$324	$717
6" WELD NECK FLANGE	2	EA	$37.00	$74	1.714	$16.89	$58	$132
6" GASKET AND BOLT SET	10	EA	$14.80	$148	1.6	$16.89	$270	$418
6" STEEL ELBOW	4	EA	$130.00	$520	2.667	$16.89	$180	$700
6" IRON BODY GATE VALVE	2	EA	$1,300.00	$2,600	8	$16.89	$270	$2,870
8" IRON BODY GATE VALVE	1	EA	$2,075.00	$2,075	9.6	$16.89	$162	$2,237
BLOWDOWN PIPING								
2" STEEL PIPE	60	LF	$4.98	$299	0.356	$16.89	$361	$660
2" STEEL ELBOW	6	EA	$59.00	$354	1.231	$16.89	$125	$479
2" IRON BODY GATE VALVE	2	EA	$475.00	$950	1	$16.89	$34	$984
2" FG PIPE INSUL, 2" WALL	40	LF	$4.19	$168	0.089	$16.89	$60	$228
SUBTOTAL				$13,260			$2,002	$15,262
OVERHEAD & BOND	0.16			$2,122			$320	$2,442
SUBTOTAL				$15,382			$2,322	$17,704
PROFIT	0.1			$1,538			$232	$1,770
SUBTOTAL				$16,920			$2,555	$19,475
CONTINGENCY	0.2			$3,384			$511	$3,895
TOTAL ESTIMATED COST				$20,304			$3,066	$23,370

LIFE CYCLE COST ANALYSIS SUMMARY
ENERGY CONSERVATION INVESTMENT PROGRAM (ECIP)

LOCATION:	HOLSTON AAP	REGION:	4
PROJ. NO. & TITLE:	DACA01-91-D-0032 LIMITED ENERGY STUDIES		
DISCRETE PORTION:	AREA A BLOWDOWN HEAT EXCHANGER		
FISCAL YEAR:	91	ECONOMIC LIFE	25
ANALYSIS DATE:	17-Jul-92	PREPARED BY: D JONES	

1 INVESTMENT

A.	CONSTRUCTION COST	=	$23,370
B.	SIOH COST	(5.5% of 1A) =	$1,285
C.	DESIGN COST	(6.0% of 1A) =	$1,402
D.	SALVAGE VALUE	=	$0
E.	TOTAL INVESTMENT	(1A + 1B +1C +1D – 1E) =	$26,058

2 ENERGY SAVINGS (+) / COST (–)

	FUEL TYPE	FUEL COST $/MBTU (1)	SAVINGS MBTU/YR (2)	ANNUAL $ SAVINGS (3)	DISCOUNT FACTOR (4)	DISCOUNTED SAVINGS (5)
A.	ELEC	$4.67	0	$0	15.61	$0
B.	DIST		0	$0	0.00	$0
C.	RESID		0	$0	0.00	$0
D.	NAT GAS		0	$0		$0
E.	COAL	$1.25	2,556	$3,195	16.06	$51,312
F.	TOTAL ENERGY SAVINGS		2,556	$3,195		$51,312

3 NON–ENERGY SAVINGS (+) / COST (–)

A. ANNUAL RECURRING

	ANNUAL $	DISCOUNT FACTOR	DISCOUNTED SAVINGS
ADDED MAINTENANCE COST	($400)	14.53	($5,812)
ELECTRIC DEMAND SAVINGS 0 KW * $9.50/KW/MTH * 12 MTHS =	$0	14.53	$0
TOTAL SAVINGS (+) / COST (–)	($400)		($5,812)

B. NON–RECURRING (+/–)

ITEM	YEAR OF OCCURRENCE			
a.		$0	0.00	$0
b.		$0	0.00	$0
c.		$0	0.00	$0
TOTAL SAVINGS (+) / COST (–)		$0		$0

C. TOTAL NON ENERGY DISCOUNTED SAVINGS (3A + 3B) ($5,812)

D. PROJECT NON–ENERGY QUALIFICATION TEST
NON ENERGY SAVINGS % (3C / (3C + 2F)) –13%

4 FIRST YEAR DOLLAR SAVINGS (+) / COSTS (–)	$2,795	
5 TOTAL NET DISCOUNTED SAVINGS		$45,500
6 DISCOUNTED SAVINGS–TO–INVESTMENT RATIO (SIR)		1.75
7 SIMPLE PAYBACK (YEARS)		9.32

APPENDIX H

AREA-B CONDENSATE COLLECTION ANALYSIS

CONDENSATE COLLECTION ECO

Condensate Sources

Turbines:

Entering conditions: 300 psig, 525°F, h_1 = 1271 Btu/lbm.

h_2 = h_1 - w,

w = 2545 (Btu/hr/hp) / SR (lbm/hp/hr), where SR is steam rate,

h_2 = 1271 - 2545 / SR,

@ 5 psig ≈ 20 psia h_f = 196 and h_g = 1156 .

Quality (X):

$$X = \frac{h_2 - 196}{1156 - 196}.$$

Turbine	Avg. Steam Demand (lbm/hr)	Steam Rate (lbm/hr/hp)	h_2 (Btu/lbm)	X	Condensate Generated (lbm/hr)
Fans	19,426	21.6	1,153	0.991	175
DA pump	2,738	60.7	1,229	SH*	0
FW pump	3,526	33.4	1,195	SH*	0

*Superheated

Superheated exhaust from pump turbines will offset pipe loss condensate generation. Remaining condensate is from fan turbines.

At 175 lbm/hr,

$$Q = 175\ lbm/hr\ x\ (200 - 56)^\circ F\ x\ 1\ Btu/lbm^\circ F = 25{,}176\ Btuh.$$

200°F = condensate temperature at make-up tank.

Make-up Water Heating

The only use for condensate heat is for make-up water heating. Average make-up flow is 143,463 lbm/hr.

Condensate will likley be 200°F from the condensate receiver. The resulting make-up water temperature is:

$$\frac{175\,lbm/hr\,x\,200^{\circ}F + 143{,}402\,lbm/hr\,x\,56}{143{,}463} = 56.2^{\circ}F.$$

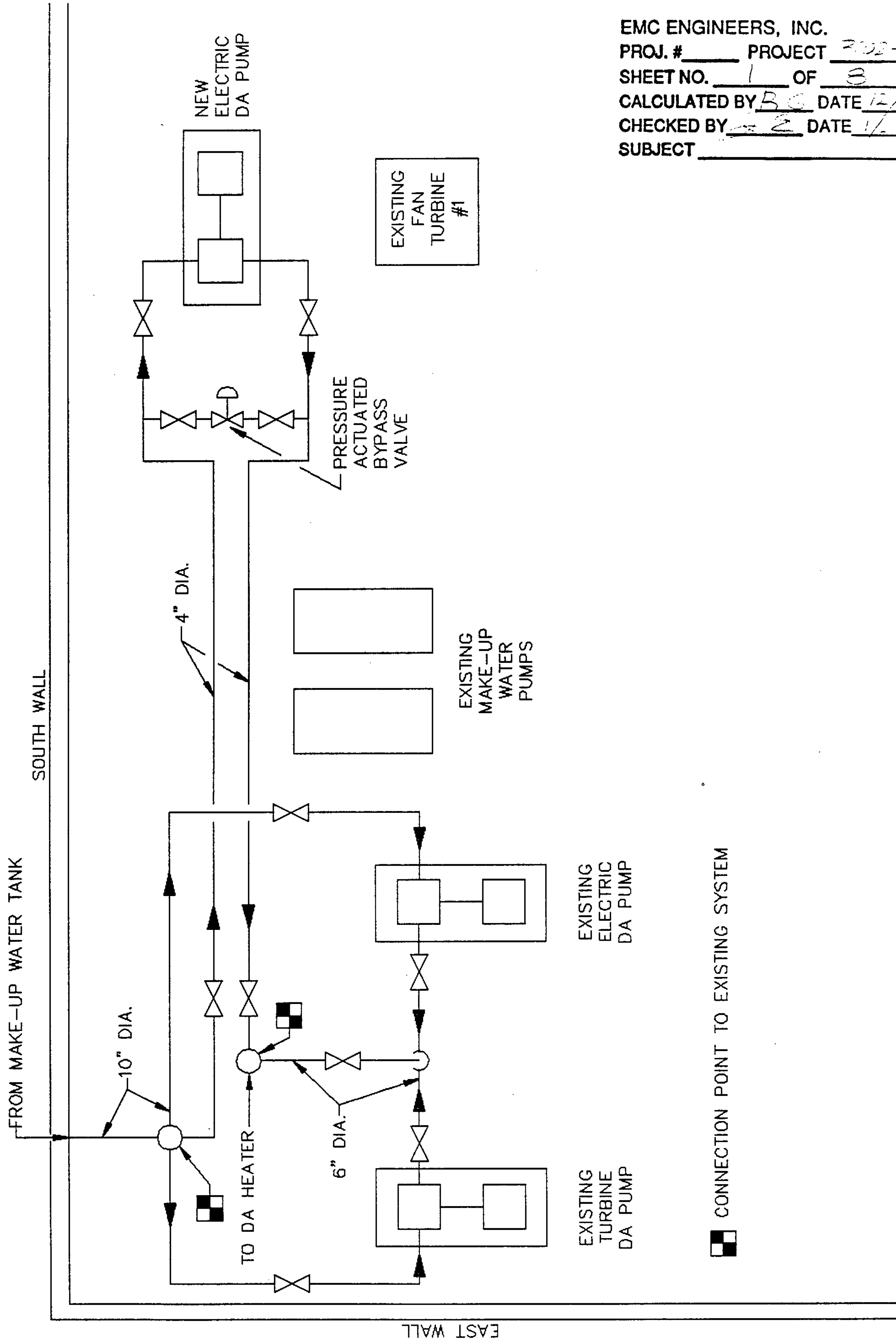
Make-up water will be heated from 56.0°F to 56.2°F.

EMC ENGINEERS, INC.
PROJ. #_____ PROJECT [illegible]
SHEET NO. 2 OF 2
CALCULATED BY [illegible] DATE [illegible]
CHECKED BY [illegible] DATE [illegible]
SUBJECT _____

APPENDIX I

AREA-A ELECTRIC DA PUMP ANALYSIS

EMC ENGINEERS, INC.
PROJ. #______ PROJECT ______
SHEET NO. 1 OF 8
CALCULATED BY ______ DATE ______
CHECKED BY ______ DATE ______
SUBJECT ______



CALCULATE PERCENT POWER REQUIRED FOR EXISTING DA PUMP

Pump Nameplate: 1200 gpm

Motor:

Model:	G.E. 84 E 86 1 G1
Frame:	5425 Type KI
Elec:	2300V 23.2 A 3 phase
Rating:	1765 rpm, 100 hp

EMC ENGINEERS, INC.
PROJ. #____ PROJECT ____
SHEET NO. ____ OF ____
CALCULATED BY ____ DATE ____
CHECKED BY ____ DATE ____
SUBJECT ____

Measured Power:

$$\frac{10.8 + 11.2 + 10.8}{3}. \quad Avg. = 10.9\ amp.$$

$$kW = \sqrt{3}\ VI = \sqrt{3}\,(2300\ V)(10.9\ A) = 43.4\ kW.$$

Calculated Power:

$$hp = \frac{h_A\ x\ gpm}{3960\ x\ \eta_p},$$

where

h_p	=	applied head (from graph),
gpm	=	actual flow = 350 gpm, and
η_p	=	efficiency (from graph).

$$hp = \frac{218\ x\ 350}{3960\ x\ 0.40} = 48.2\ hp.$$

Assuming motor efficiency of 87%, ASHRAE 1988 Equipment, p31.4.

$$kW = \frac{hp\ x\ 0.746}{eff} = \frac{(48.2)(0.746)}{0.87} = 41.3\ kW.$$

Therefore, measured power agrees with calculated power requirements.

EMC ENGINEERS, INC.
PROJ. #_____ PROJECT ________
SHEET NO. ______ OF ______
CALCULATED BY_____ DATE________
CHECKED BY_______ DATE________
SUBJECT ______________

ENERGY SAVINGS

Existing Electric Demand:

10.9 A @ 2300 V

$$\sqrt{3}\ VI = \sqrt{3}\,(2300\,V)(10.9\,A) = 43.4\,kW.$$

Proposed Electric Demand:

Pump size = 15 hp

$$\frac{15\,hp\,x\,0.746}{0.9} = 12.4\,kW.$$

Electric Demand Savings:

434 - 12.4 = 31.0 kW.

Annual Electric Energy Saivngs:

$$31.0\ kW\ x\ 8760\ hrs/yr = 271{,}560\ kWh/yr\,.$$

$$271{,}560\ kWh/yr\ x\ 0.003413\ MBtu/kWh = 927\ MBtu/yr\,.$$

EMC ENGINEERS, INC.
PROJ. #______ PROJECT ____________
SHEET NO. ______ OF ______
CALCULATED BY ______ DATE ______
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SUBJECT ____________

PRESSURE DROP CALCULATIONS

Bernoulli equation:

$$\frac{P_1}{\gamma} + Z_1 + \frac{V_1^2}{2g} + h_M = \frac{P_2}{\gamma} + Z_2 + \frac{V_2^2}{2g} + h_L .$$

where

- P_1 = 0 psi, make-up water tank,
- P_2 = 7 psi, control valve on DA heater,
- γ = specific weight, $\gamma = 62.4\ lb/ft^3$,
- Z_1 = elevation 1225 ft, top of make-up water tank,
- Z_2 = elevation 1256.25 ft, top of DA heater,
- g = 32.2 ft/sec^2,
- V = velocity, $V_1 = V_2 = 9$ ft/sec (350 gpm through 4" dia. steel pipe),
- h_L = energy losses due to piping, $H_L = 16$ ft (350 gpm through 200′ of 4" dia. steel pipe), and
- h_M = energy applied by the pump,.

To solve for h_M, rearrange the above equation thus:

$$h_M = \frac{P_2 - P_1}{\gamma} + (Z_2 - Z_1) + h_L .$$

Velocity terms cancel out.

$$h_M = \frac{7}{62.4} x\,144 + (1256.25 - 1225) + 16 = 63.4 ft ,$$

$$h_M = (63.4 x\, 1.40 = 88.8 ft ,$$

where 1.40 is the design factor.

EMC ENGINEERS, INC.
PROJ. #______ PROJECT ______
SHEET NO. ______ OF ______
CALCULATED BY ______ DATE ______
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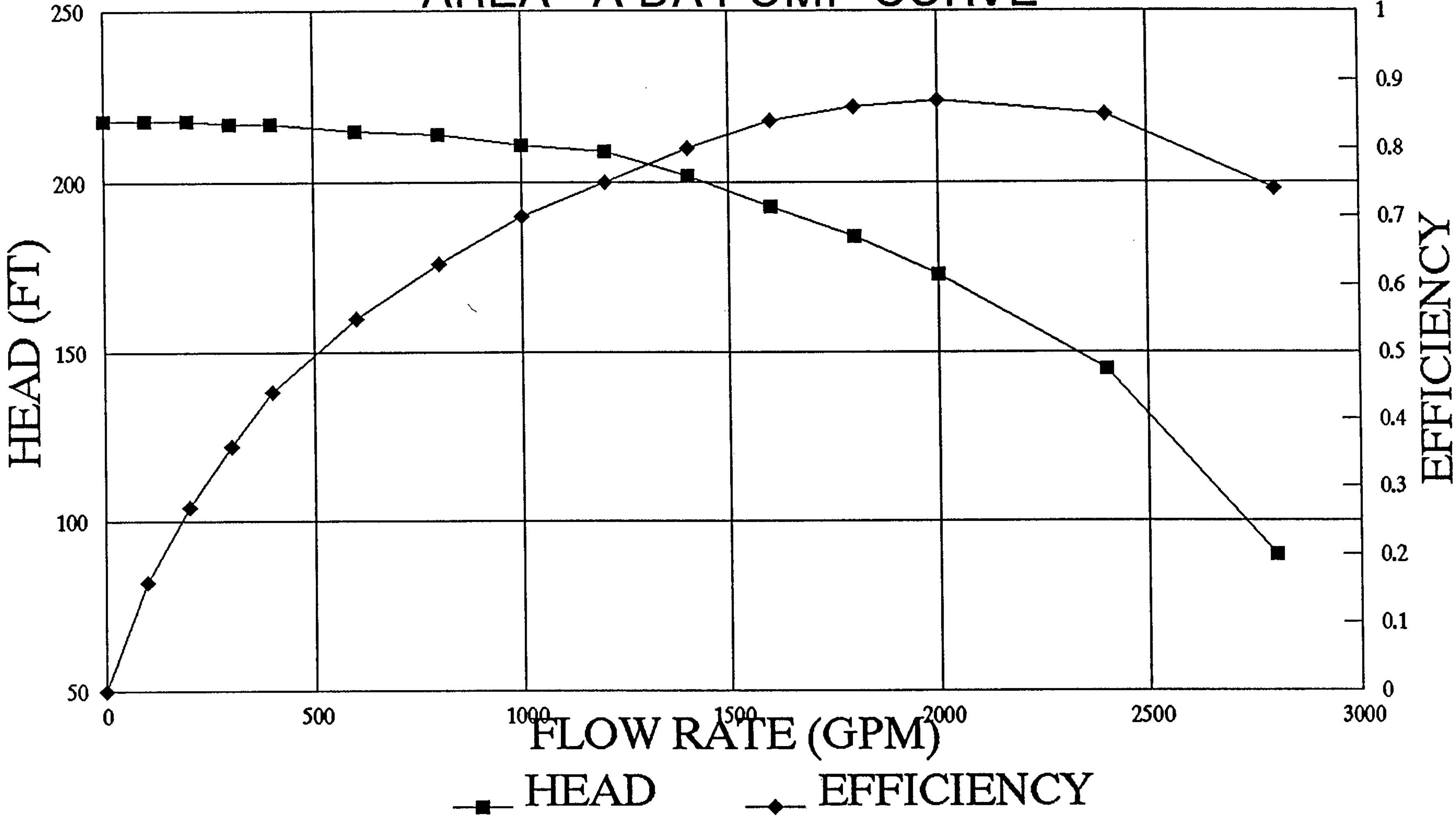
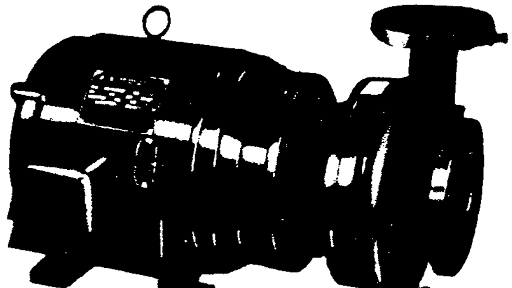
SUBJECT ______

AREA–A DA PUMP CURVE



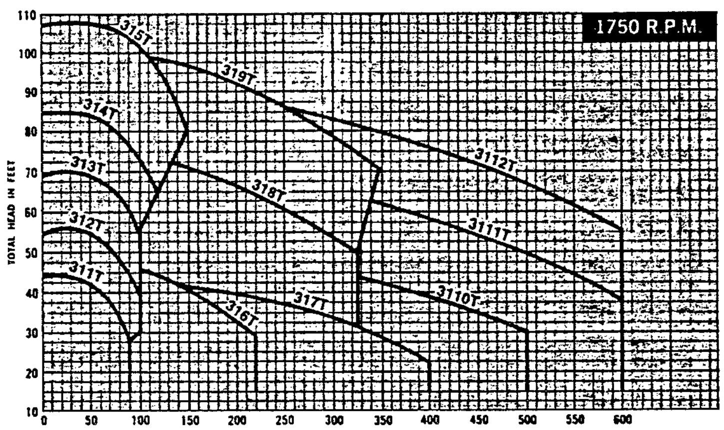


B&G Series 1531 Centrifugal Pumps

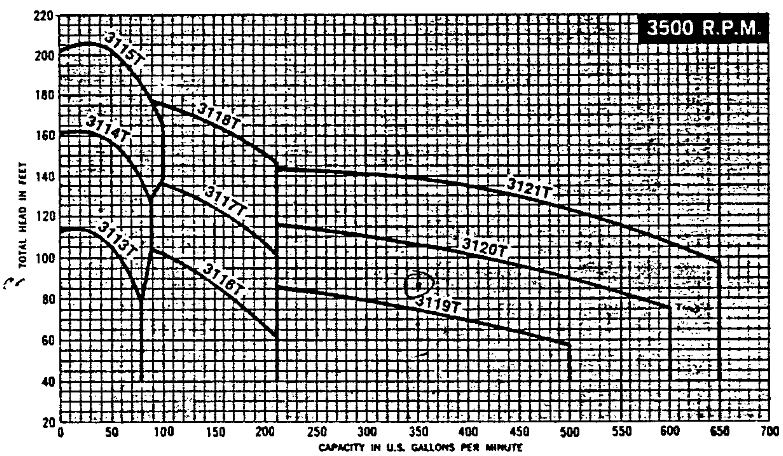
Bronze fitted construction—complete with 208 volt or 230/460 volt, 60 cycle, three phase drip-proof motors. Built-to-order units are available when conditions cannot be met by stock pump selections.

Selection Charts

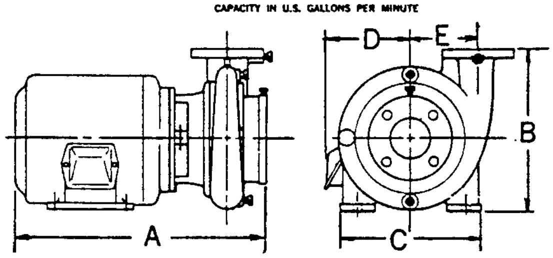
1750 RPM



3500 RPM



#1543 For Denver



Dimensions

UNIT NO.	MOTOR HP	SUCT. SIZE IN.	DISCH. SIZE IN.	APPROXIMATE DIMENSIONS IN INCHES NOT TO BE USED FOR INSTALLATION					UNIT NO.	MOTOR HP	SUCT. SIZE IN.	DISCH. SIZE IN.	APPROXIMATE DIMENSIONS IN INCHES NOT TO BE USED FOR INSTALLATION				
				A	B	C	D	E					A	B	C	D	E
311T	1	2	*1½AB	18¹³⁄₁₆	9½	7	5¾	4⅝	3112T	10	5	4BB	27⁷⁄₁₆	12¾	10½	8¾	6⅝
312T	1½	2	*1½AB	18¹³⁄₁₆	9½	7	5¾	4⅝	3113T	3	1½	*1¼AB	18½	8½	7	5¾	4½
313T	2	2	*1½BB	18¹³⁄₁₆	10	7	5¾	5¾	3114T	5	1½	*1¼AB	21⅜	9½	9	8⅛	4½
314T	3	2	*1½BB	21¹¹⁄₁₆	11	9	8⅛	5¾	3115T	7½	1½	*1¼AB	21⅜	9½	9	8⅛	4½
315T	5	2	*1½BB	21¹¹⁄₁₆	11	9	8⅛	5¾	3116T	5	2½	2AB	21⁹⁄₁₆	11	9	8⅛	4¾
316T	2	3	2½A	19⅜	9½	7	5¾	4¹¹⁄₁₆	3117T	7½	2½	2AB	21⁹⁄₁₆	11	9	8⅛	4¾
317T	3	4	3AB	23	10½	9	8⅛	5	3118T	10	2½	2AB	23¾	11¾	10½	8¾	4¾
318T	5	3	2½B	22³⁄₁₆	11¼	9	8⅛	6	3119T	10	4	3AB	25³⁄₁₆	11¼	10½	8¾	5
319T	7½	3	2½B	24⅜	12	10½	8¾	6	3120T	15	4	3AB	26¹¹⁄₁₆	11¼	10½	8¾	5
3110T	5	5	4BB	23¾	12	9	8⅛	6⅝	3121T	20	4	3AB	33½	12¼	12½	9⅞	5
3111T	7½	5	4BB	25¹⁵⁄₁₆	12¾	10½	8¾	6⅝									

*On all 1¼" and 1½" Pumps, Suction and Discharge openings are NPT threaded, all others drilled and faced per 125# ANSI standards.

7 of 7

ENGINEERS OPINION OF PROBABLE COST

Project	Holston Army Ammunition Plant Limited Energy Studies - DACA01-91-D-0032	SHEET 4 OF 1 DATE PREPARED 12/05/91
Engineer	EMC Engineers, Inc - PN# 3102-002 Denver, CO	Estimator RS
Description	DA PUMP	Checked by

Description	Quantity No. Units	Unit Meas.	Material Per Unit	Material Total	Labor Hours Per Unit	Labor Hourly Rate	Labor Total	Total Cost
NEW PUMP, 15 HP	1	EA	$1,550.00	$1,550	14.18	$16.89	$240	$1,790
PIPE, 4 in., sch 40, welded	40	LF	$6.77	$271	0.432	$16.89	$292	$563
TEE, 6 in.	2	EA	$51.00	$102	8	$16.89	$270	$372
ELBOW, 90 deg	4	EA	$13.00	$52	3.2	$16.89	$216	$268
ELBOW, 45 deg	2	EA	$9.00	$18	3.2	$16.89	$108	$126
FLANGE	10	EA	$13.00	$130	2.667	$16.89	$450	$580
CHECK VALVE	1	EA	$715.00	$715	3.2	$16.89	$54	$769
GATE VALVE	3	EA	$825.00	$2,475	5.33	$16.89	$270	$2,745
FLEX CONNECTOR	2	EA	$200.00	$400	1.5	$16.89	$51	$451
PIPE, 2 in., sch 40, welded	8	LF	$2.68	$21	0.262	$16.89	$35	$57
TEE, 4 in.	2	EA	$26.00	$52	5.33	$16.89	$180	$232
FLANGE	2	EA	$7.45	$15	1.333	$16.89	$45	$60
CONTROL VALVE	1	EA	$800.00	$800	1	$16.89	$17	$817
PRESSURE CONTROLS	1	EA	$500.00	$500	3	$16.89	$51	$551
GATE VALVE	2	EA	$475.00	$950	1	$16.89	$34	$984
VIBRATION ABSORBERS	4	EA	$24.10	$96				$96
>>ELECTRICAL<<								
CONDUIT, 1/2", galvanized steel	125	LF	$3.60	$450	0.178	$16.19	$360	$810
ELBOWS	4	EA	$11.85	$47	0.667	$16.19	$43	$91
CONDUCTOR, no. 10 THW	5	CLF	$11.70	$59	1	$16.19	$81	$139
STARTER	1	EA	$870.00	$870	8.89	$16.19	$144	$1,014
FUSE, existing panel	1	ea	$7.54	$8	0.2	$16.19	$3	$11
SUBTOTAL				$9,581			$2,944	$12,525
OVERHEAD & BOND	0.16			$1,533			$471	$2,004
SUBTOTAL				$11,114			$3,416	$14,530
PROFIT	0.1			$1,111			$342	$1,453
SUBTOTAL				$12,225			$3,757	$15,982
CONTINGENCY	0.2			$2,445			$751	$3,196
TOTAL ESTIMATED COST				$14,670			$4,509	$19,179

LIFE CYCLE COST ANALYSIS SUMMARY
ENERGY CONSERVATION INVESTMENT PROGRAM (ECIP)

LOCATION:	HOLSTON AAP	REGION:	4
PROJ. NO. & TITLE:	DACA01-91-D-0032 LIMITED ENERGY STUDIES		
DISCRETE PORTION:	AREA A ELECTRIC DA PUMP		
FISCAL YEAR:	91	ECONOMIC LIFE	25
ANALYSIS DATE:	17-Jul-92	PREPARED BY: D JONES	

1 INVESTMENT

A.	CONSTRUCTION COST		=	$19,179
B.	SIOH COST	(5.5% of 1A)	=	$1,055
C.	DESIGN COST	(6.0% of 1A)	=	$1,151
D.	SALVAGE VALUE		=	$0
E.	TOTAL INVESTMENT	(1A + 1B +1C +1D – 1E)	=	$21,385

2 ENERGY SAVINGS (+) / COST (–)

	FUEL TYPE	FUEL COST $/MBTU (1)	SAVINGS MBTU/YR (2)	ANNUAL $ SAVINGS (3)	DISCOUNT FACTOR (4)	DISCOUNTED SAVINGS (5)
A.	ELEC	$4.67	927	$4,329	15.61	$67,577
B.	DIST		0	$0	0.00	$0
C.	RESID		0	$0	0.00	$0
D.	NAT GAS		0	$0		$0
E.	COAL	$1.25	0	$0	16.06	$0
F.	TOTAL ENERGY SAVINGS		927	$4,329		$67,577

3 NON-ENERGY SAVINGS (+) / COST (–)

A. ANNUAL RECURRING

	ANNUAL $	DISCOUNT FACTOR	DISCOUNTED SAVINGS
ADDED MAINTENANCE COST	($400)	14.53	($5,812)
ELECTRIC DEMAND SAVINGS 31 KW * $9.50/KW/MTH * 12 MTHS =	$3,534	14.53	$51,349
TOTAL SAVINGS (+) / COST (–)	$3,134		$45,537

B. NON-RECURRING (+/–)

ITEM	YEAR OF OCCURRENCE	ANNUAL $	DISCOUNT FACTOR	DISCOUNTED SAVINGS
a.		$0	0.00	$0
b.		$0	0.00	$0
c.		$0	0.00	$0
TOTAL SAVINGS (+) / COST (–)		$0		$0

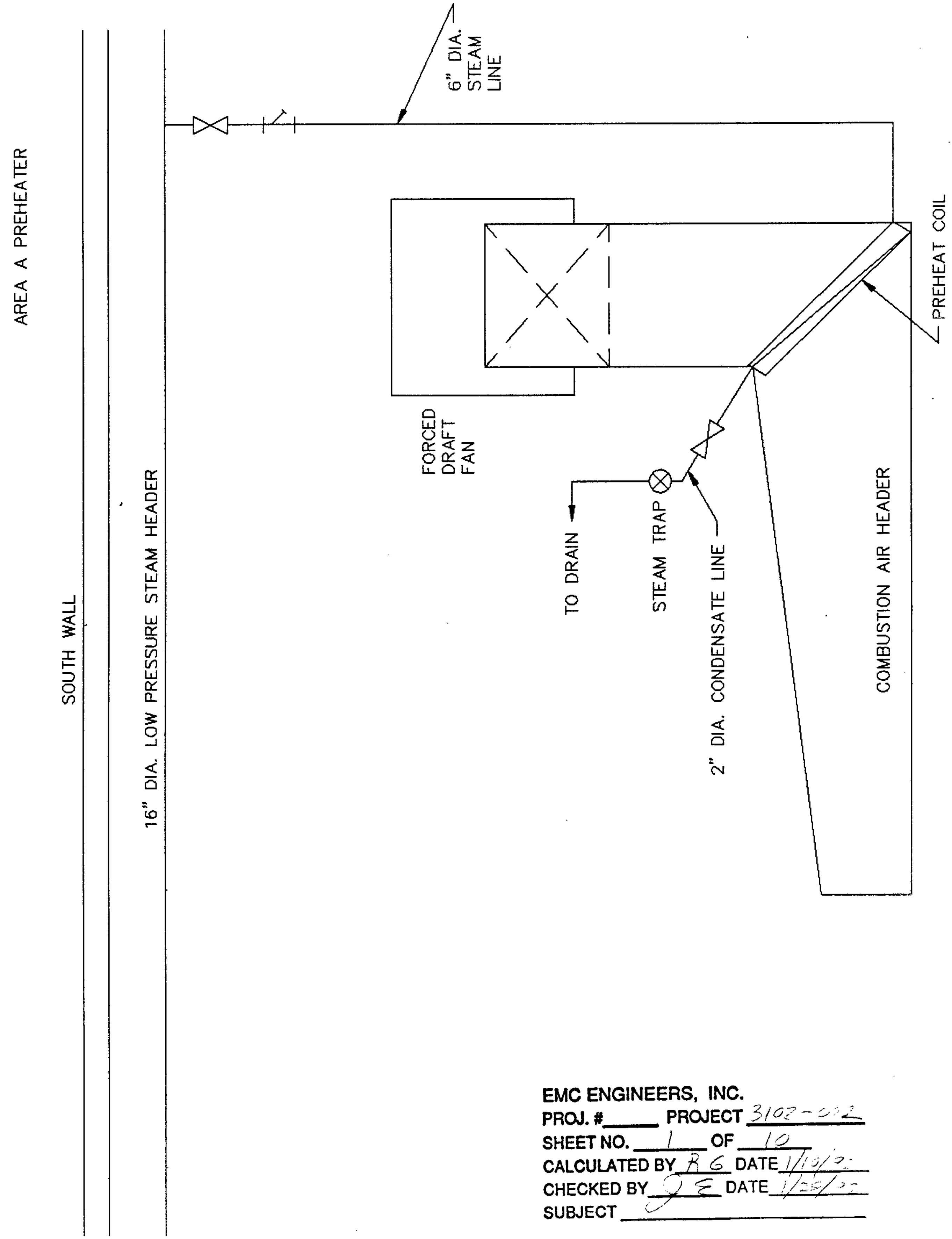
C. TOTAL NON ENERGY DISCOUNTED SAVINGS (3A + 3B) — $45,537

D. PROJECT NON-ENERGY QUALIFICATION TEST
NON ENERGY SAVINGS % (3C / (3C + 2F)) — 40%

4 FIRST YEAR DOLLAR SAVINGS (+) / COSTS (–)	$7,463
5 TOTAL NET DISCOUNTED SAVINGS	$113,114
6 DISCOUNTED SAVINGS-TO-INVESTMENT RATIO (SIR)	4.20
7 SIMPLE PAYBACK (YEARS)	2.87

APPENDIX J

AREA-A AIR PREHEATER ANALYSIS



EMC ENGINEERS, INC.
PROJ. #_____ PROJECT 3102-002
SHEET NO. 1 **OF** 10
CALCULATED BY RG **DATE** 1/10/02
CHECKED BY JE **DATE** 1/25/02
SUBJECT ____________

********** CUSTOMER DIRECT SERVICE NETWORK **********

For exclusive use by: Trane Customer Direct Service Network

STEAM COIL SELECTION AVERAGE OPERATING UNIT

PROGRAM VERSION: 6.08 RUN DATE: 01/10/92

PROJECT : HOLSTON ENERGY STUDY
LOCATION : HOLSTON ARMY BASE
OWNER :
USER : R. GERRANS
COMMENTS :

EMC ENGINEERS, INC.
PROJ. #_____ PROJECT 3155-001
SHEET NO. 2 OF 10
CALCULATED BY RG DATE 1/12/92
CHECKED BY CZ DATE 1/28/92
SUBJECT J

INPUT DATA

ELEVATION 0.

TAG	SCFM	EAT	PSI	WIDTH	LENGTH	FA	FV
AVG	23040.	56.0	5.0	60.	94.	39.17	588.

LAT	MBH	COIL TYPE	ROW	CIS	FIN TYPE	FPF	SH
.0	.0	A	0.	1.	SF	168.	0.

OUTPUT DATA

TAG	TYPE	ROW	COILS IN SERIES	FIN TYPE	FINS PER FOOT	MBH	LAT	APD	LBS COND/HR	SPD
AVG	A	1	1	SF	168.	1992.9	135.8	.22	2071.8	.454

DIAGNOSTIC MESSAGES
ACTUAL CFM ENTERED.

DATA CERTIFIED IN ACCORDANCE WITH ARI STANDARD 410
EXCEPT WHERE * DENOTES OPERATING CONDITIONS WHICH
EXCEED ARI RATING RANGES.

$$EFFECTIVENESS = \frac{LAT - EAT}{T_{STEAM} - EAT} = \frac{136 - 56}{227 - 56} = 46.7\%$$

********** CUSTOMER DIRECT SERVICE NETWORK **********

For exclusive use by: Trane Customer Direct Service Network

STEAM COIL SELECTION DESIGN OPERATING [illegible]

PROGRAM VERSION: 6.08 RUN DATE: 01/10/92

PROJECT : HOLSTON ENERGY STUDY
LOCATION : HOLSTON ARMY BASE
OWNER :
USER : R. GERRANS
COMMENTS :

EMC ENGINEERS, INC.
PROJ. #____ PROJECT 3152-[illegible]
SHEET NO. 3 OF 10
CALCULATED BY [illegible] DATE [illegible]
CHECKED BY [illegible] DATE 1/28/92
SUBJECT

INPUT DATA

ELEVATION 0.

TAG	SCFM	EAT	PSI	WIDTH	LENGTH	FA	FV
DESIGN	40007.	56.0	5.0	60.	94.	39.17	1021.

LAT	MBH	COIL TYPE	ROW	CIS	FIN TYPE	FPF	SH
.0	.0	A	0.	1.	SF	168.	0.

OUTPUT DATA

TAG	TYPE	ROW	COILS IN SERIES	FIN TYPE	FINS PER FOOT	MBH	LAT	APD	LBS COND/HR	SPD
DESIGN	A	1	1	SF	168.	2599.3	115.9	.57	2699.7	.770

DIAGNOSTIC MESSAGES
ACTUAL CFM ENTERED.

DATA CERTIFIED IN ACCORDANCE WITH ARI STANDARD 410
EXCEPT WHERE * DENOTES OPERATING CONDITIONS WHICH
EXCEED ARI RATING RANGES.

AREA-A COMPUTER BOILER MODEL - AIR PREHEATER

BOILAAIR.WK3

HEATING VALUE OF COAL	HHV	14100.00	BTU/LBM	COAL ANALYSIS
THEORETICAL COMBUSTION AIR	THEO	11.00	LBM/LBM	LBH AIR/LBH COAL FROM ASHRAE FUNDAMENTALS
MIXED WATER TEMP	RETURN	130.00	F	LBH OF 5 PSI STEAM CONDENSED PER LBH OF MAKE UP
LATENT HEAT (5 PSI)	PSI5	960.00	BTU/LBM	STEAM TABLES
ECONOMOZER AIR TEMP IN	TEI	480	F	MEASURED
ECONOMIZER UA	ECON	26000.00	BTUH/F	AREA-A ECONOMIZER ANALYSIS
BLOWDOWN RATE	BLOW	2.46%	%	MEASURED
STEAM ENTHALPY	HS	1291.00	BTU/LBM	300 PSI, 626 F
LIQUID ENTHALPY	HL	428	BTU/LBM	300 PSI, SATURATED
LOW PRES STEAM ENTHALPY	HSLP	1,157	BTU/LBM	5 PSIG, SAT
DA HEATER LIQUID ENTHALPY	HLDA	196	BTU/LBM	228 F, SAT
AMBIENT TEMPERATURE	TA	56	F	WEATHER DATA
COMBUSTION LOSSES	LOSS	0.00%	%	ASSUMED
RADIATION LOSSES PER BOILER	RAD	1.65	MBH	ASSUMED
DESIGN FAN HORSEPOWER	FANHP	550	HP	DESIGN DATA
DESIGN FAN CFM	FANCFM	62,600	CFM	DESIGN DATA
FAN STEAM RATE	FANSTM	19.20	LBM/HP/HR	TURBINE MANUFACTURER
DA PUMP DESIGN HORSEPOWER	DAHP	80	HP	DESIGN DATA
DA PUMP DESIGN FLOW	DAGPM	1,750	GPM	DESIGN DATA
DA PUMP STEAM RATE	DASTM	0.0	LBM/HP/HR	TURBINE MANUFACTURER
FW PUMP DESIGN HORSEPOWER	FWHP	136	HP	DESIGN DATA
FW PUMP DESIGN FLOW	FWGPM	460	GPM	DESIGN DATA
FW PUMP STEAM RATE	FWSTM	30.8	LBM/HP/HR	TURBINE MANUFACTURER
BLOWDOWN FLASH STEAM	FLASH	24.20%	%	CALCULATED
FW PUMP HEAD	FWHEAD	1,000	FT	CALCULATED
VACUUM STEAM JET RATE	JET	444	LBM/HR	CALCULATED
INTERMEDIATE HEADER PRESSU	IHP	5	PSIG	
INTERMEDIATE HEADER TEMP	IHT	228	F	
PRE-HEATER EFFECTIVENESS	IHE	0.00		
PRE-HEATER LATENT HEAT	IHH	960	BTU/LBM	
LOW PRESSURE STEAM TEMP	LPT	228	F	

							BLOWDOWN HEAT RECOVERY			DEAERATING HEATER				DA PUMPS			FEEDWATER PUMP	
CONDITION	NUMBER OF DAYS	CHP STEAM DEMAND (LBM/HR)	CHP STEAM BALANCE (LBM/HR)	BOILER STEAM FLOW (LBM/HR)	BOILERS ON LINE	TOTAL FEED WATER (LBM/HR)	BLOW DOWN LIQUID (LBM/HR)	HEAT EXCHANGE EFF	HEAT TRANSFER (BTUH)	LEAVING MAKE UP TEMP (F)	5 PSI STEAM (LBM/HR)	MAKE UP WATER (LBM/HR)	LEAVING MAKE UP TEMP (F)	DA PUMP FLOW (GPM)	DA PUMP POWER (HP)	DA PUMP STEAM (LBM/HR)	FW PUMP FLOW (GPM)	FW PUMP POWER (HP)
BASELINE	30	90,700	(0)	108,921	2	111,600	2,031	0.00	0	130	10,337	101,263	228	203	32	0	224	81
AIR PREHEATER	30	90,700	0	108,231	2	110,894	2,018	0.00	0	130	10,272	100,622	228	202	32	0	223	80

EMC ENGINEERS, INC.
PROJ. #_____ PROJECT _____
SHEET NO. 4 OF _____
CALCULATED BY _____ DATE _____
CHECKED BY _____ DATE _____
SUBJECT _____

AREA-A COMP BOILER MODEL - AIR PREHEATER

BOILAAIR.WK3 DA PUMP CURVE

GPM	HEAD	EFF	HP	PLR	%HP
0	218	0%	0	0%	0%
100	218	16%	34	5%	34%
200	218	27%	41	10%	41%
300	217	36%	46	15%	45%
400	217	44%	50	20%	50%
600	216	55%	59	30%	59%
800	214	63%	69	40%	68%
1,000	211	70%	76	50%	76%
1,200	209	75%	84	60%	84%
1,400	202	80%	89	70%	89%
1,600	193	84%	93	80%	92%
1,800	184	86%	97	90%	97%
2,000	173	87%	100	100%	100%
2,400	145	85%	103	120%	103%
2,800	90	74%	86	140%	86%

PART LOAD	STEAM OUT	BLOWDOWN	DRY FLUE L	FLUE HUMI	RADIATION	COMBUSTION LOSS
BASECASE	77.94%	0.75%	15.25%	3.89%	2.17%	0.00%
DESIGN	84.86%	0.82%	8.06%	3.89%	2.37%	0.00%

		STEAM PRE-HEATER			STEAM AIR PREHEATER				BOILER INCLUDING ECONOMIZER									
CONDITION	FW PUMP STEAM (LBM/HR)	HEAT TRANSFER (BTUH)	STEAM DEMAND (LBM/HR)	LEAVING FW TEMP (F)	HEAT EXCHANGE EFF	ENERGY EXCHANGE (BTUH)	PRE HEAT EXIT (F)	STEAM USAGE (LBM/HR)	STEAM OUT (LBM/HR)	BOILER FEED WATER (LBM/HR)	ESTMTD OXYGEN	PERCENT EXCESS AIR	COMBUST AIR FLOW (LBM/HR)	STEAM OUT (MBH)	FDW IN (MBH)	STEAM PRODUCED (MBH)	BLOW DOWN LOSS (MBH)	DRY FLUE LOSS (MBH)
BASELINE	2,824	0	0	228	0.00	0	56	0	54,460	55,800	12.37%	143%	144,564	70	11	59	1	12
AIR PREHEATER	2,811	0	0	228	0.46	4,458,028	196	3,853	54,116	55,447	12.39%	144%	132,292	70	11	59	1	6

EMC ENGINEERS, INC.
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AREA-A COMPUTER BOILER MODEL - AIR PREHEATER

BOILAAIR.WK3	DA PUMP	FW PUMP	FANS	MISCELLAN	STEAM TO LOAD
	0	2,824	14,306	1,092	90,700

								ECONOMIZER					DRAFT FANS				CENTRAL HEATING PLA	
CONDITION	FUEL HUMIDITY LOSS (MBH)	RADIATION LOSS (MBH)	COMBUST LOSSES (MBH)	FUEL IN (MBH)	COAL FLOW (LBM/HR)	FLUE GAS FLOW (LBM/HR)	BOILER EFF	CAPACITY RATIO	NTU	EFF	EXIT AIR (F)	EXIT WATER (F)	FORCED DRAFT (SCFM)	INDUCED DRAFT (SCFM)	TOTAL HP	FAN STEAM (LBM/HR)	BLOW DOWN FLASH (LBM/HR)	TOTAL LO PRES STEAM (LBM/HR)
BASELINE	3	2	0	76	5,402	149,697	77.9%	0.64	0.70	0.44	369	302	32,126	33,266	328	7,162	648	17,777
AIR PREHEATER	3	2	0	70	4,931	136,976	84.9%	0.59	0.76	0.47	361	301	29,398	30,439	306	6,816	644	17,087

EMC ENGINEERS, INC.
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AREA-A COM BOILER MODEL - AIR PREHEATER

BOILAAIR.WK3

NT

CONDITION	EXCESS LO PRES STEAM (LBM/HR)	EXCESS LO PRES VENT (LBM/HR)	PRV STEAM (LBM/HR)	TOTAL IN PLANT STEAM (LBM/HR)	TOTAL IN PLANT STEAM (LBM/HR)	STEAM TO LOAD (LBM/HR)	FUEL IN (MBH)	MONTHLY FUEL IN (MBH)	STEAM TO LOAD (MBH)	MAKE UP WATER (MBH)	CHP ENERGY ADDED (MBH)	CHP EFF	STEAM JET (MBH)	FLUE LOSS (MBH)	COMBUSTI LOSS (MBH)	EXCESS STEAM VENT (MBH)
BASELINE	7,439	7,439	0	18,221	16.73%	90,700	152.3	109,690	117	10	107	70.3%	1	29	0	8.607
AIR PREHEATER	6,816	6,816	0	17,531	16.20%	90,700	139.0	100,111	117	10	107	77.1%	1	17	0	7.886

EMC ENGINEERS, INC.
PROJ. #____ PROJECT ____
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ENERGY SAVINGS

(From Boiler Model)

Fuel (IN):

Baseline	152.3 MBtuh
Preheater	139.0 MBtuh
	13.3 MBtuh x 8,760 hr/yr = 113,880 Mbtu/yr.

Maintenance Costs:

40 hours @ $25 = $1000/yr.

EMC ENGINEERS, INC.
PROJ. #_____ PROJECT 3122-002
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ENGINEERS OPINION OF PROBABLE COST

Project	Holston Army Ammunition Plant Limited Energy Studies – DACA01-91-D-0032	**DATE PREPARED** 07/17/92
Engineer	EMC Engineers, Inc – PN# 3102-002 Denver, CO	**Estimator** D JONES
Description	AREA A AIR PREHEATERS	**Checked by**

Description	Quantity		Material		Labor			Total Cost
	No. Units	Unit Meas.	Per Unit	Total	Hours Per Unit	Hourly Rate	Total	
16 IN REDUCING TEE	4	EA	$350.00	$1,400	20	$16.89	$1,351	$2,751
6 IN PIPE								
PIPE	120	FT	$25.10	$3,012	0.8	$16.89	$1,621	$4,633
TEE	4	EA	$42.00	$168	8	$16.89	$540	$708
GATE VALVE	4	EA	2025	$8,100	8	$16.89	$540	$8,640
STRAINER	4	EA	686	$2,744	8	$16.89	$540	$3,284
ELBOW	16	EA	$45.00	$720	5.3	$16.89	$1,432	$2,152
FLANGE	28	EA	$24.00	$672	2.4	$16.89	$1,135	$1,807
1 IN PIPE								
PIPE	120	FT	$1.54	$185	0.151	$16.89	$306	$491
TEE	12	EA	$3.00	$36	1	$16.89	$203	$239
ELBOW	32	EA	$1.85	$59	0.615	$16.89	$332	$392
GATE VALVE	32	EA	$14.00	$448	0.421	$16.89	$228	$676
STRAINER	32	EA	$14.85	$475	0.5	$16.89	$270	$745
UNION	32	EA	$7.40	$237	0.667	$16.89	$361	$597
CAP	32	EA	$1.15	$37	0.267	$16.89	$144	$181
STEAM TRAP	32	EA	$110.00	$3,520	0.533	$16.89	$288	$3,808
STEAM COIL	4	EA	$2,400.00	$9,600	80	$16.89	$5,405	$15,005
SUBTOTAL				$31,413			$14,698	$46,111
OVERHEAD & BOND	0.16			$5,026			$2,352	$7,378
SUBTOTAL				$36,439			$17,050	$53,488
PROFIT	0.1			$3,644			$1,705	$5,349
SUBTOTAL				$40,083			$18,755	$58,837
CONTINGENCY	0.2			$8,017			$3,751	$11,767
TOTAL ESTIMATED COST				$48,099			$22,505	$70,605

LIFE CYCLE COST ANALYSIS SUMMARY
ENERGY CONSERVATION INVESTMENT PROGRAM (ECIP)

LOCATION:	HOLSTON AAP	REGION:	4
PROJ. NO. & TITLE:	DACA01-91-D-0032 LIMITED ENERGY STUDIES		
DISCRETE PORTION:	AREA A AIR PREHEATER		
FISCAL YEAR:	91	ECONOMIC LIFE	25
ANALYSIS DATE:	17-Jul-92	PREPARED BY: D JONES	

1 INVESTMENT

A.	CONSTRUCTION COST	=	$70,605
B.	SIOH COST	(5.5% of 1A) =	$3,883
C.	DESIGN COST	(6.0% of 1A) =	$4,236
D.	SALVAGE VALUE	=	$0
E.	TOTAL INVESTMENT	(1A + 1B +1C +1D – 1E) =	$78,725

2 ENERGY SAVINGS (+) / COST (–)

	FUEL TYPE	FUEL COST $/MBTU (1)	SAVINGS MBTU/YR (2)	ANNUAL $ SAVINGS (3)	DISCOUNT FACTOR (4)	DISCOUNTED SAVINGS (5)
A.	ELEC	$4.67	0	$0	15.61	$0
B.	DIST		0	$0	0.00	$0
C.	RESID		0	$0	0.00	$0
D.	NAT GAS		0	$0		$0
E.	COAL	$1.25	113,880	$142,350	16.06	$2,286,141
F.	TOTAL ENERGY SAVINGS		113,880	$142,350		$2,286,141

3 NON-ENERGY SAVINGS (+) / COST (–)

A. ANNUAL RECURRING

	ANNUAL $	DISCOUNT FACTOR	DISCOUNTED SAVINGS
ADDED MAINTENANCE COST	($1,000)	14.53	($14,530)
ELECTRIC DEMAND SAVINGS 0 KW * $9.50/KW/MTH * 12 MTHS =	$0	14.53	$0
TOTAL SAVINGS (+) / COST (–)	($1,000)		($14,530)

B. NON-RECURRING (+/–)

ITEM	YEAR OF OCCURRENCE	ANNUAL $	DISCOUNT FACTOR	DISCOUNTED SAVINGS
a.		$0	0.00	$0
b.		$0	0.00	$0
c.		$0	0.00	$0
TOTAL SAVINGS (+) / COST (–)		$0		$0

C. TOTAL NON ENERGY DISCOUNTED SAVINGS (3A + 3B) ($14,530)

D. PROJECT NON-ENERGY QUALIFICATION TEST
NON ENERGY SAVINGS % (3C / (3C + 2F)) –1%

4 FIRST YEAR DOLLAR SAVINGS (+) / COSTS (–)	$141,350
5 TOTAL NET DISCOUNTED SAVINGS	$2,271,611
6 DISCOUNTED SAVINGS-TO-INVESTMENT RATIO (SIR)	28.86
7 SIMPLE PAYBACK (YEARS)	0.56

APPENDIX K

INLET AIR DAMPER ANALYSIS

EMC ENGINEERS, INC.
PROJ. #_____ PROJECT _____
SHEET NO. _____ OF _____
CALCULATED BY _____ DATE _____
CHECKED BY _____ DATE _____
SUBJECT _____

INLET AIR DAMPERS

Field Measurements:

Area-B:
Measured 700 fpm entering through 6'H x 12'W lower door 72 ft^2.
Six roof openings at 11.5' x 6.5' $\Rightarrow$ 450 ft^2.

Area-A:
Six roof openings at 12' x 7.5' $\Rightarrow$ 540 ft^2.

Analysis of Existing Condition:

Average of 85,000 cfm of combustion air required for two boilers.
During the field survey, boiler operation was near average.

Measured 700 fpm x 6' x 12' = 50,400 cfm entering door.
Assuming radiation losses are 1% of full load,

$$Q = 1\% \, x \, 160{,}000 \, lbm \, x \, 1028 \, Btu/lbm = 1.65 \, MBH/boiler.$$

Two boilers $\Rightarrow$ 3.29 MBH radiation loss.

The following temperatures were measured:

60°F at the forced draft fan inlet
60°F outside air
71°F on firing floor
90°F above boilers.

Flow past boilers was

$$\frac{3.29 \, x \, 10^6 \, Btu/hr^\circ F \, hr \, cfm}{1.08 \, Btu (90^\circ F - 60^\circ F)} = 102{,}000 \, cfm.$$

Flow out	=	102,000 cfm
Combustion	=	85,000 cfm
Inlet Air	=	187,000 cfm*

*Flow entering building through lower door and other openings.

The above analysis indicates measured temperatures, calculated airflows, and assumed radiation loss are properly related.

From the above analysis, the following may be assumed:

t_c = t_a, combustion air temperature equals outside air temperature,

t_e = $t_c + 30$, exit air temperature is 30°F above combustion air temperature. and

t_r = $0.67\ t_c + 0.33\ t_e$, firing floor room temperature is weighted average of combustion air temperature. and exit air temperature

Modified System:

With inlet air dampers in place, only dampers over hot boilers would be open. Combustion air would be heated by boiler heat loss according to the following relation:

$$t_c = \frac{t_a + Q_R}{(1.08\ x\ cfm)}$$

where

Q_R = boiler heat loss, and

cfm = combustion air required.

Room temperature is assumed to be equal to combustion air temperature. If room temperature exceeds 80°F, all dampers are opened for maximum ventilation.

Monthly temperatures were calculated in the following spreadsheet.

Annual Average Combustion Temperature was raised from 56°F to 76°F.

Modified combustion air temperatures were input into computer boiler models.

Area-B

Annual coal usage was lowered from 2,155,572 MBtu to 2,130,727 MBtu.
Average efficiency was raised from 71.5% to 73.3%.

Annual coal savings was 24,845 MMBtu.

Area-A

Annual coal usage was lowered from 152.3 MMBtu to 150.2
Average efficiency was raied from 77.9% to 78.9%.
Annual coal savings was 18,079 MMBtu.

Total Energy Savings for Areas A and B is 42,924 MBtu.

EMC ENGINEERS, INC.
PROJ. #______ PROJECT ______
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INLET AIR DAMPERS

This spreadsheet calculates combustion air and room temperatures with and without inlet air dampers.

MONTH	DAYS	AMBIENT TEMP (F)	STEAM PRODUCTION (1000LBH)	COMBUST AIR (1000LBH)	COMBUST AIR (CFM)	BOILER HEAT LOSS (MMBH)	EXISTING CONDITION: COMBUST AIR TEMP (F)	EXISTING CONDITION: EXISTING EXHAUST TEMP (F)	EXISTING CONDITION: EXISTING ROOM TEMP (F)	MODIFIED CONDITION: COMBUST AIR TEMP (F)	MODIFIED CONDITION: WINTER ROOM TEMP (F)
Jan	31	35	202	476	105,849	3,290,000	35	65	45	64	64
Feb	28	38	209	493	109,517	3,290,000	38	68	48	66	66
Mar	31	46	177	417	92,749	3,290,000	46	76	56	79	79
Apr	30	56	168	396	88,033	3,290,000	56	86	66	80	80
May	31	64	144	340	75,457	3,290,000	64	94	74	80	80
Jun	30	72	140	330	73,361	3,290,000	72	102	82	80	82
Jul	31	75	136	321	71,265	3,290,000	75	105	85	80	85
Aug	31	74	136	321	71,265	3,290,000	74	104	84	80	84
Sep	30	69	143	337	74,933	3,290,000	69	99	79	80	80
Oct	31	57	155	365	81,221	3,290,000	57	87	67	80	80
Nov	30	46	182	429	95,369	3,290,000	46	76	56	78	78
Dec	31	38	195	460	102,181	3,290,000	38	68	48	68	68
	365	56	166	390	86,767	3,290,000	56	86	66	76	77

EMC ENGINEERS, INC.
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CHECKED BY [illegible] DATE [illegible]
SUBJECT ______

AREA-B COMPUTER BOILER MODEL - INLET AIR DAMPERS

DAMPERECO.WK3

EMC ENGINEERS, INC.
PROJ. # ____ PROJECT 3162-002
SHEET NO. 4 OF 16
CALCULATED BY ____ DATE 1/29/92
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HEATING VALUE OF COAL	HHV	14100.00	BTU/LBM	COAL ANALYSIS
THEORETICAL COMBUSTION AIR	THEO	11.00	LBM/LBM	LBH AIR/LBH COAL FROM ASHRAE FUNDAMENTALS
MIXED WATER TEMP	RETURN	56.00	F	LBH OF 5 PSI STEAM CONDENSED PER LBH OF MAKE UP
LATENT HEAT (5 PSI)	PSI5	960.00	BTU/LBM	STEAM TABLES
ECONOMOZER AIR TEMP IN	TEI	480	F	MEASURED
ECONOMIZER UA	ECON	25000.00	BTUH/F	AREA-A ECONOMIZER ANALYSIS
BLOWDOWN RATE	BLOW	2.46%	%	MEASURED
STEAM ENTHALPY	HS	1271.00	BTU/LBM	300 PSI, 525 F
LIQUID ENTHALPY	HL	399	BTU/LBM	300 PSI, SATURATED
LOW PRES STEAM ENTHALPY	HSLP	1,157	BTU/LBM	5 PSIG, SAT
DA HEATER LIQUID ENTHALPY	HLDA	196	BTU/LBM	228 F, SAT
AMBIENT TEMPERATURE	TA	76	F	WEATHER DATA
COMBUSTION LOSSES	LOSS	8.10%	%	ASSUMED
RADIATION LOSSES PER BOILER	RAD	1.66	MMBH	ASSUMED
DESIGN FAN HORSEPOWER	FANHP	550	HP	DESIGN DATA
DESIGN FAN CFM	FANCFM	62,500	CFM	DESIGN DATA
FAN STEAM RATE	FANSTM	21.60	LBH/HP	TURBINE MANUFACTURER
DA PUMP DESIGN HORSEPOWER	DAHP	80	HP	DESIGN DATA
DA PUMP DESIGN FLOW	DAGPM	1,750	GPM	DESIGN DATA
DA PUMP STEAM RATE	DASTM	64.8	LBH/HP	TURBINE MANUFACTURER
FW PUMP DESIGN HORSEPOWER	FWHP	135	HP	DESIGN DATA
FW PUMP DESIGN FLOW	FWGPM	450	GPM	DESIGN DATA
FW PUMP STEAM RATE	FWSTM	33.4	LBH/HP	TURBINE MANUFACTURER
BLOWDOWN FLASH STEAM	FLASH	21.10%	%	CALCULATED
FW PUMP HEAD	FWHEAD	700	FT	CALCULATED
VACUUM STEAM JET RATE	JET	932	LBH	CALCULATED
INTERMEDIATE HEADER PRESSU	IHP	5	PSIG	
INTERMEDIATE HEADER TEMP	IHT	228	F	
PRE-HEATER EFFECTIVENESS	IHE	0.80		
PRE-HEATER LATENT HEAT	IHH	950	BTU/LBM	
LOW PRESSURE STEAM TEMP	LPT	228	F	

CONDITION	NUMBER OF DAYS	CHP STEAM DEMAND (LBM/HR)	CHP STEAM BALANCE (LBM/HR)	BOILER STEAM FLOW (LBM/HR)	BOILERS ON LINE	TOTAL FEED WATER (LBM/HR)	BLOWDOWN HEAT RECOVERY: BLOW DOWN LIQUID (LBM/HR)	HEAT EXCHANGE EFF	HEAT TRANSFER (BTUH)	LEAVING MAKE UP TEMP (F)	DEAERATING HEATER: 5 PSI STEAM (LBM/HR)	MAKE UP WATER (LBM/HR)	LEAVING MAKE UP TEMP (F)	DA PUMPS: DA PUMP FLOW (GPM)	DA PUMP POWER (HP)	DA PUMP STEAM (LBM/HR)	FEEDWATER PUMP: FW PUMP FLOW (GPM)	FW PUMP POWER (HP)
BASECASE	30	135,200	0	161,706	2	165,684	3,139	0.00	0	56	25,176	140,509	228	282	36	2,472	333	84
DESIGN	30		539,432	640,000	4	655,744	12,422	0.00	0	56	99,636	556,106	228	1,117	67	3,826	1,317	333
JAN	31	172,191	0	205,045	2	210,089	3,980	0.00	0	56	31,922	178,167	228	368	40	2,616	422	107
FEB	28	166,877	0	198,751	2	203,640	3,858	0.00	0	56	30,942	172,698	228	357	36	2,472	409	103
MAR	31	151,466	0	180,498	2	184,938	3,503	0.00	0	56	28,100	156,838	228	347	36	2,472	371	94
APR	30	139,980	0	166,894	2	171,000	3,239	0.00	0	56	25,982	145,018	228	315	36	2,472	343	87
MAY	31	123,623	0	149,247	2	152,918	2,897	0.00	0	56	23,235	129,683	228	291	36	2,472	307	78
JUN	30	117,555	(0)	142,798	2	146,311	2,772	0.00	0	56	22,231	124,080	228	260	32	2,301	294	74
JUL	31	116,885	0	142,085	2	145,581	2,758	0.00	0	56	22,120	123,461	228	249	32	2,301	292	74
AUG	31	116,907	0	142,109	2	145,606	2,758	0.00	0	56	22,124	123,481	228	248	32	2,301	292	74
SEP	30	119,133	0	144,476	2	148,030	2,804	0.00	0	56	22,492	125,538	228	248	32	2,301	297	75
OCT	31	132,672	0	159,028	2	162,940	3,087	0.00	0	56	24,758	138,182	228	262	32	2,301	327	83
NOV	30	151,630	0	180,692	2	185,137	3,507	0.00	0	56	28,130	157,007	228	277	36	2,472	372	94
DEC	31	166,331	0	198,104	2	202,977	3,845	0.00	0	56	30,841	172,136	228	315	36	2,472	408	103

EMC ENGINEERS, INC.
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AREA-B COMP BOILER MODEL - INLET AIR DAMPERS

DAMPERECO.WK3 DA PUMP CURVE

GPM	HEAD	EFF	HP	PLR	%HP
0	218	0%	0	0%	0%
100	218	16%	34	5%	34%
200	218	27%	41	10%	41%
300	217	36%	46	15%	46%
400	217	44%	50	20%	50%
600	216	55%	59	30%	59%
800	214	63%	69	40%	68%
1,000	211	70%	76	50%	76%
1,200	209	75%	84	60%	84%
1,400	202	80%	89	70%	89%
1,600	193	84%	93	80%	92%
1,800	184	86%	97	90%	97%
2,000	173	87%	100	100%	100%
2,400	146	85%	103	120%	103%
2,800	90	74%	86	140%	86%

PART LOAD	STEAM OUT	BLOWDOWN	DRY FLUE L	FLUE HUMID	RADIATION	COMBUSTION LOSS
BASECASE	73.34%	0.67%	12.59%	3.89%	1.40%	8.10%
DESIGN	77.68%	0.71%	8.87%	3.89%	0.76%	8.10%

		STEAM PRE-HEATER			COMBUSTION AIR PREHEAER			BOILER INCLUDING ECONOMIZER										
CONDITION	FW PUMP STEAM (LBM/HR)	HEAT TRANSFER (BTUH)	STEAM DEMAND (LBM/HR)	LEAVING FW TEMP (F)	HEAT EXCHANGE EFF	ENERGY EXCHANGE (BTUH)	PRE HEAT EXIT (F)	FLUE GAS EXIT (F)	STEAM OUT (LBM/HR)	BOILER FEED WATER (LBM/HR)	ESTMTD OXYGEN	PERCENT EXCESS AIR	COMBUST AIR FLOW (LBM/HR)	STEAM OUT (MBH)	FDW IN (MBH)	STEAM PRODUCED (MBH)	BLOW DOWN LOSS (MBH)	DRY FLUE LOSS (MBH)
BASECASE	3,147	0	0	228	0.00	0	76	385	80,853	82,842	10.61%	102%	185,978	103	16	87	1	15
DESIGN	9,787	0	0	228	0.00	0	76	397	160,000	163,936	6.33%	34%	230,436	203	32	171	2	20
JAN	3,748	0	0	228	0.00	0	76	390	102,622	105,044	9.16%	77%	202,726	130	21	110	1	17
FEB	3,661	0	0	228	0.00	0	76	389	99,376	101,820	9.37%	81%	200,694	126	20	106	1	16
MAR	3,408	0	0	228	0.00	0	76	387	90,249	92,469	9.98%	91%	193,873	116	18	97	1	16
APR	3,219	(0)	(0)	228	0.00	0	76	386	83,447	85,500	10.43%	99%	188,268	106	17	89	1	16
MAY	2,974	0	0	228	0.00	0	76	383	74,623	76,459	11.02%	110%	180,093	95	15	80	1	14
JUN	2,884	0	0	228	0.00	0	76	382	71,399	73,156	11.24%	115%	176,812	91	14	76	1	14
JUL	2,874	0	0	228	0.00	0	76	382	71,043	72,790	11.26%	116%	176,439	90	14	76	1	14
AUG	2,875	0	0	228	0.00	0	76	382	71,054	72,802	11.26%	116%	176,461	90	14	76	1	14
SEP	2,907	0	0	228	0.00	0	76	382	72,238	74,015	11.18%	114%	177,682	92	15	77	1	14
OCT	3,109	0	0	228	0.00	0	76	386	79,514	81,470	10.70%	104%	184,760	101	16	86	1	15
NOV	3,410	0	0	228	0.00	0	76	387	90,346	92,569	9.97%	90%	193,949	116	18	97	1	16
DEC	3,652	0	0	228	0.00	0	76	389	99,052	101,489	9.39%	81%	200,370	126	20	106	1	16

EMC ENGINEERS, INC.
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AREA-B COMPUTER BOILER MODEL - INLET AIR DAMPERS

DAMPERECO.WK3	DA PUMP	FW PUMP	DRAFT FAN	MISCELLAN	STEAM TO LOAD
	2,472	3,147	19,116	1,771	136,200

								ECONOMIZER					DRAFT FANS				CENTRAL HEATING PLA	
CONDITION	FUEL HUMIDITY LOSS (MBH)	RADIATION LOSS (MBH)	COMBUST LOSSES (MBH)	FUEL IN (MBH)	COAL FLOW (LBM/HR)	FLUE GAS FLOW (LBM/HR)	BOILER EFF	CAPACITY RATIO	NTU	EFF	EXIT AIR (F)	EXIT WATER (F)	FORCED DRAFT (SCFM)	INDUCED DRAFT (SCFM)	TOTAL HP	FAN STEAM (LBM/HR)	BLOW DOWN FLASH (LBM/HR)	TOTAL LO PRES STEAM (LBM/HR)
BASECASE	5	2	10	118	8,367	193,927	73.3%	0.56	0.54	0.38	386	283	41,328	43,095	416	9,558	839	25,574
DESIGN	9	2	18	220	15,634	245,287	77.7%	0.36	0.42	0.33	397	269	51,208	54,508	533	11,584	3,322	63,271
JAN	6	2	12	146	10,389	212,596	74.9%	0.49	0.49	0.36	390	273	46,060	47,244	457	10,272	1,064	27,974
FEB	6	2	12	142	10,098	210,187	74.7%	0.50	0.50	0.36	389	274	44,577	46,708	452	10,178	1,032	27,521
MAR	5	2	11	130	9,248	202,669	74.1%	0.53	0.51	0.37	387	278	43,083	45,036	435	9,887	937	26,591
APR	5	2	10	121	8,611	196,449	73.6%	0.55	0.53	0.37	386	282	41,837	43,655	421	9,662	866	25,861
MAY	4	2	9	110	7,779	187,483	72.8%	0.59	0.56	0.38	383	287	40,021	41,663	402	9,321	776	24,692
JUN	4	2	9	105	7,472	183,911	72.5%	0.60	0.57	0.39	382	289	39,292	40,869	394	9,192	741	24,311
JUL	4	2	8	105	7,438	183,505	72.5%	0.61	0.57	0.39	382	289	39,209	40,779	394	9,178	738	24,268
AUG	4	2	8	105	7,439	183,519	72.5%	0.60	0.57	0.39	382	289	39,211	40,782	394	9,178	738	24,270
SEP	4	2	9	106	7,552	184,857	72.6%	0.60	0.56	0.39	382	288	39,485	41,079	396	9,226	750	24,411
OCT	5	2	9	116	8,241	192,589	73.2%	0.57	0.54	0.38	385	284	41,068	42,798	413	9,509	825	25,424
NOV	5	2	11	131	9,258	202,744	74.1%	0.53	0.51	0.37	387	278	43,100	45,054	435	9,891	938	26,601
DEC	6	2	11	142	10,068	209,935	74.7%	0.50	0.50	0.36	389	275	44,527	46,652	451	10,168	1,028	27,489

EMC ENGINEERS, INC.
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AREA-B COM BOILER MODEL - INLET AIR DAMPERS

DAMPERECO.WK3

NT

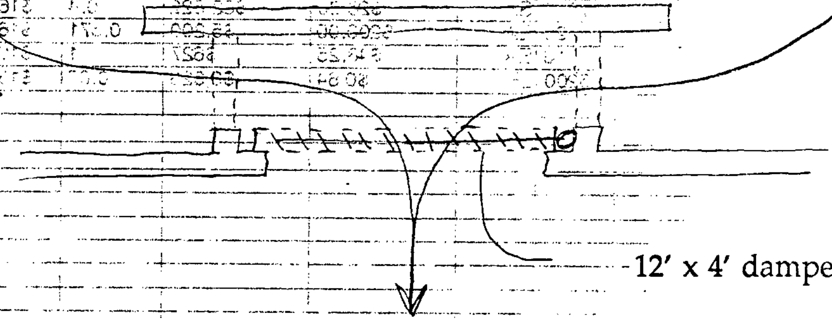
CONDITION		EXCESS LO PRES STEAM (LBM/HR)	EXCESS LO PRES VENT (LBM/HR)	PRV STEAM (LBM/HR)	TOTAL IN PLANT STEAM (LBM/HR)	TOTAL IN PLANT STEAM	STEAM TO LOAD (LBM/HR)	FUEL IN (MBH)	MONTHLY FUEL IN (MBH)	STEAM TO LOAD (MBH)	MAKE UP WATER (MBH)	CHP ENERGY ADDED (MBH)	CHP EFF	STEAM JET (MBH)	FLUE LOSS (MBH)	COMBUSTI LOSS (MBH)	EXCESS STEAM VENT (MBH)
BASECASE		399	399	0	26,506	16.39%	135,200	236.0	169,890	172	3	168	71.4%	1	39	19	0.462
DESIGN		(36,365)	0	36,365	100,568	15.71%	639,432	881.7	634,863	686	13	672	76.2%	1	113	71	0.000
	JAN	(3,948)	0	3,948	32,854	16.02%	172,191	293.0	217,975	219	4	215	73.2%	1	44	24	0.000
	FEB	(3,421)	0	3,421	31,874	16.04%	166,877	284.8	191,356	212	4	208	73.0%	1	44	23	0.000
	MAR	(1,509)	0	1,509	29,032	16.08%	161,466	260.8	194,041	193	4	189	72.4%	1	41	21	0.000
	APR	(121)	0	121	26,914	16.13%	139,980	242.8	174,846	178	3	174	71.8%	1	40	20	0.000
	MAY	1,457	1,457	0	25,624	17.17%	123,623	219.4	163,201	157	3	154	70.2%	1	37	18	1.686
	JUN	2,080	2,080	0	25,243	17.68%	117,555	210.7	161,717	149	3	146	69.6%	1	36	17	2.407
	JUL	2,148	2,148	0	25,200	17.74%	116,886	209.8	166,062	149	3	146	69.4%	1	36	17	2.486
	AUG	2,146	2,146	0	25,202	17.73%	116,907	209.8	156,086	149	3	146	69.4%	1	36	17	2.483
	SEP	1,919	1,919	0	25,343	17.54%	119,133	213.0	153,338	151	3	148	69.7%	1	36	17	2.220
	OCT	666	666	0	26,356	16.57%	132,672	232.4	172,905	169	3	166	71.1%	1	39	19	0.771
	NOV	(1,629)	0	1,629	29,062	16.08%	151,630	261.1	187,966	193	4	189	72.4%	1	41	21	0.000
	DEC	(3,353)	0	3,353	31,773	16.04%	166,331	283.9	211,230	211	4	207	73.0%	1	44	23	0.000
									2,130,722								

K-7

INLET AIR DAMPERS

Construction Costs:

Install in 24" sections.



MEANS:

Operable louvers: [157 - 482 - 2540].
$26.30/SF + 0.40 MH/SF.

Motor operator, pneumatic or electric: [157 - 482 - 2560].
$200/EA + 0.571 MH/EA.

1/4" pneumatic tubing: [157 - 420 - 9416].
$0.64/LF + 0.07 MH/LF.

Pneumatic switch: [157 - 420 - 9361].
$4.25/EA + 1 MH/EA.

Assume each damper assembly will require:

2	motors		26
1	switch	(x 13 roof openings)	13
400	feet of tubing		5200
96	ft² louvers		1248

EMC ENGINEERS, INC.
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ENGINEERS OPINION OF PROBABLE COST

SHEET ~~1~~9 OF 10

Project	Holston Army Ammunition Plant Limited Energy Studies – DACA01-91-D-0032	DATE PREPARED 11/25/91
Engineer	EMC Engineers, Inc – PN# 3102-002 Denver, CO	Estimator
Description	INLET AIR DAMPERS AREAS A&B	Checked by

Description	Quantity		Material		Labor			Total Cost
	No. Units	Unit Meas.	Per Unit	Total	Hours Per Unit	Hourly Rate	Total	
OPERABLE LOUVERS	1248	SF	$26.30	$32,822	0.4	$16.45	$8,212	$41,034
PNEUMATIC MOTORS	26	EA	$200.00	$5,200	0.571	$16.45	$244	$5,444
PNEUMATIC SWITCHES	13	EA	$48.25	$627	1	$16.45	$214	$841
PNEUMATIC TUBING	5200	LF	$0.64	$3,328	0.07	$16.45	$5,988	$9,316
SUBTOTAL				$41,978			$14,658	$56,635
OVERHEAD & BOND	0.16			$6,716			$2,345	$9,062
SUBTOTAL				$48,694			$17,003	$65,697
PROFIT	0.1			$4,869			$1,700	$6,570
SUBTOTAL				$53,563			$18,703	$72,267
CONTINGENCY	0.2			$10,713			$3,741	$14,453
TOTAL ESTIMATED COST				$64,276			$22,444	$86,720

LIFE CYCLE COST ANALYSIS SUMMARY
ENERGY CONSERVATION INVESTMENT PROGRAM (ECIP)

LOCATION:	HOLSTON AAP	REGION:	4
PROJ. NO. & TITLE:	DACA01-91-D-0032 LIMITED ENERGY STUDIES		
DISCRETE PORTION:	INLET AIR DAMPERS		
FISCAL YEAR:	91	ECONOMIC LIFE	25
ANALYSIS DATE:	17-Jul-92	PREPARED BY: D JONES	

1 INVESTMENT

A.	CONSTRUCTION COST	=	$86,720
B.	SIOH COST	(5.5% of 1A) =	$4,770
C.	DESIGN COST	(6.0% of 1A) =	$5,203
D.	SALVAGE VALUE	=	$0
E.	TOTAL INVESTMENT	(1A + 1B +1C +1D – 1E) =	$96,693

2 ENERGY SAVINGS (+) / COST (–)

	FUEL TYPE	FUEL COST $/MBTU (1)	SAVINGS MBTU/YR (2)	ANNUAL $ SAVINGS (3)	DISCOUNT FACTOR (4)	DISCOUNTED SAVINGS (5)
A.	ELEC	$4.67	0	$0	15.61	$0
B.	DIST		0	$0	0.00	$0
C.	RESID		0	$0	0.00	$0
D.	NAT GAS		0	$0		$0
E.	COAL	$1.25	42,924	$53,655	16.06	$861,699
F.	TOTAL ENERGY SAVINGS		42,924	$53,655		$861,699

3 NON-ENERGY SAVINGS (+) / COST (–)

A. ANNUAL RECURRING

ADDED MAINTENANCE COST	($400)	14.53	($5,812)
ELECTRIC DEMAND SAVINGS 0 KW * $9.50/KW/MTH * 12 MTHS =	$0	14.53	$0
TOTAL SAVINGS (+) / COST (–)	($400)		($5,812)

B. NON-RECURRING (+/–)

ITEM	YEAR OF OCCURRENCE			
a.		$0	0.00	$0
b.		$0	0.00	$0
c.		$0	0.00	$0
TOTAL SAVINGS (+) / COST (–)		$0		$0

C. TOTAL NON ENERGY DISCOUNTED SAVINGS (3A + 3B) ($5,812)

D. PROJECT NON-ENERGY QUALIFICATION TEST
NON ENERGY SAVINGS % (3C / (3C + 2F)) –1%

4 FIRST YEAR DOLLAR SAVINGS (+) / COSTS (–)	$53,255
5 TOTAL NET DISCOUNTED SAVINGS	$855,887
6 DISCOUNTED SAVINGS-TO-INVESTMENT RATIO (SIR)	8.85
7 SIMPLE PAYBACK (YEARS)	1.82